Except as provided in the Plan, as of the Effective Date, all non-Debtor entities are permanently enjoined from commencing or continuing in any manner, any action or proceeding, whether directly, derivatively, on account of or respecting any claim, debt, right or cause of action of the Debtors, the Debtors in Possession or the Reorganized Debtors which the Debtors, the Debtors in Possession or the Reorganized Debtors, as the case may be, retain sole and exclusive authority to pursue in accordance with Section 28.1 of the Plan or which has been released pursuant to the Plan, including, without limitation, pursuant to Sections 2.1, 28.3 and 42.6 of the Plan, provided, however, that, except with regard to the Debtors, the Debtors in Possession and the Reorganized Debtors, such injunction is not intended, nor shall it be construed to, extend to the ongoing prosecution of the Class Actions.

X. Summary of Other Provisions of the Plan

1. Preservation of Rights of Action

Except as otherwise provided in the Plan, including, without limitation, Articles XXII and XXIII of the Plan, or in any contract, instrument, release or other agreement entered into in connection with the Plan, in accordance with section 1123(b) of the Bankruptcy Code, the Reorganized Debtors shall retain sole and exclusive authority to enforce any claims, rights or causes of action that the Debtors, the Debtors in Possession or their chapter 11 estates may hold against any Entity, including any claims, rights or causes of action arising under sections 541, 544, 545, 547, 548, 549, 550, 551 and 553 of the Bankruptcy Code.

2. Payment of Statutory Fees

All fees payable pursuant to section 1930 of title 28 of the United States Code, as determined by the Bankruptcy Court at the Confirmation Hearing, shall be paid on the Effective Date.

3. Retiree Benefits

From and after the Effective Date, pursuant to section 1129(a)(13) of the Bankruptcy Code, the Reorganized Debtors shall continue to pay all retiree benefits (within the meaning of section 1114 of the Bankruptcy Code), if any, at the level established in accordance with subsection (e)(1)(B) or (g) of section 1114 of the Bankruptcy Code, at any time prior to the Confirmation Date, and for the duration of the period during which the Debtors have obligated themselves to provide such benefits; provided, however, that the Debtors or the Reorganized Debtors may modify such benefits to the extent permitted by applicable law.

4. Retention of Documents

Notwithstanding the terms and provisions of that certain Stipulation and Consent Order Pursuant to 11 U.S.C. §105 and 541 By and Between Enron Corp. and Its Affiliated Debtors-in-Possession and the Official Committee of Unsecured Creditors Regarding Document Preservation and Retention, dated February 15, 2002, unless otherwise ordered by the Bankruptcy Court, from and after the first (1st) anniversary of the Confirmation Date, the Debtors and each Enron Affiliate shall have the right and authorization to destroy or otherwise dispose of the Documents, as defined therein.

5. Post-Confirmation Date Fees and Expenses

From and after the Confirmation Date, the Reorganized Debtors shall, in the ordinary course of business and without the necessity for any approval by the Bankruptcy Court, (a) retain such professionals and (b) pay the reasonable professional fees and expenses incurred by the Reorganized Debtors and the Creditors' Committee related to implementation and consummation of the Plan, including, without limitation, reasonable fees and expenses of the Indenture Trustees incurred in connection with the distributions to be made pursuant to the Plan.

6. Severability

If, prior to the Confirmation Date, any term or provision of the Plan shall be held by the Bankruptcy Court to be invalid, void or unenforceable, including, without limitation, the inclusion of one (1) or more of the Debtors in the Plan, the Bankruptcy Court shall, with the consent of the Debtors and the Creditors' Committee, have the power to alter and interpret such term or provision to make it valid or enforceable to the maximum extent practicable, consistent with the original purpose of the term or provision held to be invalid, void or unenforceable, and such term or provision shall then be applicable as altered or interpreted. Notwithstanding any such holding, alteration or interpretation, the remainder of the terms and provisions of the Plan shall remain in full force and effect and shall in no way be affected, impaired or invalidated by such holding, alteration or interpretation. The Confirmation Order shall constitute a judicial determination and shall provide that each term and provision of the Plan, as it may have been altered or interpreted in accordance with the foregoing, is valid and enforceable pursuant to its terms

7. Amendment of Articles of Incorporation and By-Laws

The articles of incorporation and by-laws of the Debtors shall be amended as of the Effective Date to provide substantially as set forth in the Reorganized Debtors Certificate of Incorporation and the Reorganized Debtors By-laws.

8. Corporate Action

On the Effective Date, the adoption of the Reorganized Debtors Certificate of Incorporation and the Reorganized Debtors By-laws shall be authorized and approved in all respects, in each case without further action under applicable law, regulation, order, or rule, including, without limitation, any action by the stockholders of the Debtors or the Reorganized Debtors. The cancellation of all Equity Interests and other matters provided under the Plan involving the corporate structure of the Reorganized Debtors or corporate action by the Reorganized Debtors shall be deemed to have occurred, be authorized, and shall be in effect without requiring further action under applicable law, regulation, order, or rule, including, without limitation, any action by the stockholders of the Debtors or the Reorganized Debtors. Without limiting the foregoing, from and after the Confirmation Date, the Debtors, the Reorganized Debtors and the Reorganized Debtor Plan Administrator may take any and all actions deemed appropriate in order to consummate the transactions contemplated in the Plan and, notwithstanding any provision contained in the Debtors' articles of incorporation and by-laws to the contrary, such Entities shall not require the affirmative vote of holders of Equity

Interests in order to take any corporate action including to (i) consummate a Sale Transaction, (ii) compromise and settle claims and causes of action of or against the Debtors and their chapter 11 estates, and (iii) dissolve, merge or consolidate with any other Entity.

9. Exculpation

None of the Debtors, the Reorganized Debtors, the Creditors' Committee, the Employee Committee, the Indenture Trustees responsible for making distributions under the Plan, and any of their respective directors, officers, employees, members, attorneys, consultants, advisors and agents (acting in such capacity), shall have or incur any liability to any Entity for any act taken or omitted to be taken in connection with and subsequent to the commencement of the Chapter 11 Cases, the formulation, preparation, dissemination, implementation, confirmation or approval of the Plan or any compromises or settlements contained therein, the Disclosure Statement related thereto or any contract, instrument, release or other agreement or document provided for or contemplated in connection with the consummation of the transactions set forth in the Plan; provided, however, that the foregoing provisions of Section 42.7 of the Plan shall not affect the liability of any Entity that otherwise would result from any such act or omission to the extent that such act or omission is determined in a Final Order to have constituted gross negligence or willful misconduct. Any of the foregoing parties in all respects shall be entitled to rely upon the advice of counsel with respect to their duties and responsibilities under the Plan.

10. Modification of Plan

The Debtors reserve the right, in accordance with the Bankruptcy Code and the Bankruptcy Rules, subject to the consent of the Creditors' Committee and, in the event any amendment or modification would materially adversely affect the substance of the economic and governance provisions set forth in the Plan, including, without limitation, Article II of the Plan, the ENA Examiner as Plan facilitator, to amend or modify the Plan, the Plan Supplement or any exhibits to the Plan at any time prior to the entry of the Confirmation Order. Upon entry of the Confirmation Order, the Debtors may, subject to the consent of the Creditors' Committee, upon order of the Bankruptcy Court, amend or modify the Plan, in accordance with section 1127(b) of the Bankruptcy Code, or remedy any defect or omission or reconcile any inconsistency in the Plan in such manner as may be necessary to carry out the purpose and intent of the Plan. A holder of a Claim that has accepted the Plan shall be deemed to have accepted the Plan as modified if the proposed modification does not materially and adversely change the treatment of the Claim of such holder.

11. Revocation or Withdrawal

a. The Plan may be revoked or withdrawn prior to the Confirmation Date by the Debtors.

b. If the Plan is revoked or withdrawn prior to the Confirmation Date, or if the Plan does not become effective for any reason whatsoever, then the Plan shall be deemed null and void. In such event, nothing contained in the Plan shall be deemed to constitute a waiver or release of any claims by the Debtors or any other Entity or to prejudice in any manner the rights of the Debtors or any other Entity in any further proceedings involving the Debtors.

12. Creditors' Committee – Term and Fees

From and after the Effective Date, the Creditors' Committee shall be authorized only to perform the following functions:

a. to prosecute, or to continue to prosecute, as the case may be, claims on behalf of the Debtors' estates against individual insiders of the Debtors; provided, however, that, if any such claims constitute Special Litigation Trust Claims, such claims and causes of action shall be assigned to the Special Litigation Trust and prosecuted by the Special Litigation Trustee for and on behalf of the Special Litigation Trust and the beneficiaries thereof; and

b. to complete litigation, other than such litigation referenced in Section 33.1(a) of the Plan, if any, to which the Creditors' Committee is a party as of the Effective Date.

From and after the Effective Date, the Reorganized Debtors shall pay the reasonable fees and expenses of professionals the Creditors' Committee retains or continues the retention of to satisfy the obligations and duties set forth in Section 33.1 of the Plan and shall reimburse the members of the Creditors' Committee for reasonable disbursements incurred. The Creditors' Committee shall be dissolved and the members thereof and the professionals retained by the Creditors' Committee in accordance with section 1103 of the Bankruptcy Code shall be released and discharged from their respective fiduciary obligations, upon the earlier to occur of (y) resolution of all litigation to which the Creditors' Committee is a party and (z) the entry of a Final Order dissolving the Creditors' Committee. Notwithstanding the foregoing, (1) the members of the Creditors' Committee which serve on a joint task force with the Debtors with respect to the prosecution of Litigation Trust Claims shall continue to serve from and after the Effective Date and (2) the professionals retained by the Creditors' Committee with respect thereto shall continue such retention until a Final Order has been entered (i) approving a compromise and settlement of all of the Litigation Trust Claims or (ii) determining the Litigation Trust Claims set forth in the MegaClaim Litigation and any other similar litigation.

13. Employee Committee – Term and Fees

From and after the Confirmation Date, the Employee Committee shall be authorized only to perform the following functions:

a. to prosecute, or continue to prosecute, as the case may be, Deferred Compensation Litigation and Severance Settlement Fund Litigation; and

b. to complete litigation, other than such litigation referenced in Section 33.2(a) of the Plan, if any, to which the Employee Committee is a party as of the Confirmation Date.

From and after the Confirmation Date, the Debtors or the Reorganized Debtors, as the case may be, shall pay the reasonable fees and expenses of professionals the Employee Committee retains or continues the retention of to satisfy the obligations and duties associated with the Deferred Compensation Litigation; provided, however, that in connection with the Settlement Fund Litigation, counsel to the Employee Committee shall continue to serve as counsel to the Severance Settlement Fund Trustee and be compensated and reimbursed in accordance with the provisions of the Severance Settlement Fund Trust Agreement and the Severance Settlement Fund Order. The Employee Committee shall be dissolved and the member thereof and the professionals retained by the Employee Committee in accordance with section 327, 328 or 1102 of the Bankruptcy Code shall be released and discharged from their respective fiduciary obligations upon the earlier to occur of (y) resolution of all litigation to which the Employee Committee is a party and (z) the entry of a Final Order dissolving the Employee Committee.

14. Examiners – Terms and Fees

Except as provided below, on the tenth (10th) day following the Confirmation Date, each of the ENE Examiner, the ENA Examiner and the professionals retained by each of the ENE Examiner and the ENA Examiner shall be released and discharged from their respective obligations outstanding pursuant to the Investigative Orders of the Bankruptcy Court; provided, however, that, notwithstanding the foregoing, during the period from the Confirmation Date up to and including (a) the earlier to occur of (1) the Confirmation Order becoming a Final Order and (2) the Effective Date, and (b) the appointment of the board of directors as described in the last sentence of Section 40.1 of the Plan, the ENA Examiner shall continue its other duties and obligations pursuant to orders of the Bankruptcy Court. On or prior to the thirtieth (30th) day following the Confirmation Date, and except as (y) otherwise available on a centralized, coded filing system available to the Debtors and the Creditors' Committee or (z) as prohibited by any existing confidentiality order entered by the Bankruptcy Court or other confidentiality agreement executed by the ENE Examiner or the ENA Examiner, as the case may be, each of the ENE Examiner and the ENA Examiner shall deliver to the Reorganized Debtors and the Creditors' Committee (i) one copy of each report filed by such Person in the Chapter 11 Cases, (ii) all material cited in the footnotes of any such report, (iii) any other materials, including, without limitation, transcripts, interview memoranda, witness folders and transactional documents and summaries thereof, produced, developed or compiled by the ENE Examiner or the ENA Examiner, in each case in connection with the Investigative Orders and (iv) a schedule of all materials which such Entity is, or claims to be, precluded from delivering to the Debtors or the Creditors' Committee, in each case in connection with the Investigative Orders.

15. Fee Committee – Term and Fees

From and after the Confirmation Date, the members of the Fee Committee and the Fee Committee's employees and representatives shall continue to serve and be authorized to perform the following functions:

a. to review, analyze and prepare advisory reports with respect to applications for the payment of fees and the reimbursement of expenses of professionals retained in the Chapter 11 Cases pursuant to an order of the Bankruptcy Court during the period up to and including the Confirmation Date, including, without limitation, final fee applications in accordance with sections 328, 330, 331 and 503 of the Bankruptcy Code; and

b. if necessary, appear before the Bankruptcy Court with respect to any such application.

From and after the Confirmation Date, the Reorganized Debtors shall pay the reasonable fees and expenses of the members of the Fee Committee and the Fee Committee's employees and representatives to satisfy the obligations and duties set forth in Section 30.4 of the Plan. Notwithstanding the foregoing, the Fee Committee shall be dissolved and the members thereof and the employees and professionals retained by the Fee Committee shall be released and discharged from their respective obligations upon the earlier to occur of (i) the one (1) year anniversary of the Confirmation Date and (ii) satisfaction of the obligations and duties set forth in Section 33.4 of the Plan.

16. Mediator – Term and Fees

From and after the Confirmation Date and until such time as the Mediator terminates all efforts with respect thereto, the Reorganized Debtors shall continue to participate in the mediation required by the Mediation Orders. In accordance with the Mediation Orders, the Reorganized Debtors shall be responsible for their one-third (1/3) share of the Mediator's expenses and such expenses shall be treated as Administrative Expense Claims in accordance with the provisions of the Plan and the Confirmation Order.

17. Employee Counsel

From and after the Confirmation Date and until such time as the board of directors of Reorganized ENE determines otherwise, all counsel retained and authorized to provide services to then-current employees of the Debtors pursuant to the Employee Counsel Orders shall continue to provide services to such employees in accordance with the provisions contained therein; provided, however, that, nothing contained in Section 33.6 of the Plan shall inhibit, prejudice or otherwise affect the rights of the Creditors' Committee with respect to its appeals of the Employee Counsel Orders in connection with fees and expenses incurred prior to the Confirmation Date.

VII. Estate Management And Liquidation

Capitalized terms used throughout this Disclosure Statement are defined in Appendix A: "Material Defined Terms for Enron Disclosure Statement" attached hereto.

A. Post-Effective Date

1. Role of the Reorganized Debtor Plan Administrator

On the Effective Date, compliance with the provisions of the Plan will become the general responsibility of the Reorganized Debtor Plan Administrator, an employee of the Reorganized Debtors (subject to the supervision of the Board of Directors of the Reorganized Debtors), pursuant to and in accordance with the provisions of the Plan and the Reorganized Debtor Plan Administration Agreement. The responsibilities of the Reorganized Debtor Plan Administrator shall include (a) facilitating the Reorganized Debtors' prosecution or settlement of objections to and estimations of Claims, (b) prosecuting or settling claims and causes of action held by the Debtors and Debtors in Possession, (c) assisting the Litigation Trustee and the Special Litigation Trustee in performing their respective duties, (d) calculating and assisting the Disbursing Agent in implementing all distributions in accordance with the Plan, (e) filing all required tax returns and paying taxes and all other obligations on behalf of the Reorganized Debtors from funds held by the Reorganized Debtors, (f) reporting periodically to the Bankruptcy Court regarding the status of the Claims resolution process, distributions on Allowed Claims and prosecution of causes of action, (g) liquidating the Remaining Assets and providing for the distribution of the net proceeds thereof in accordance with the provisions of the Plan, and (h) such other responsibilities as may be vested in the Reorganized Debtor Plan Administrator pursuant to the Plan, the Reorganized Debtor Plan Administration Agreement or Bankruptcy Court order as may be necessary and proper to carry out the provisions of the Plan.

Additionally**,** the Reorganized Debtor Plan Administrator's powers will, without any further Bankruptcy Court approval in each of the following cases, include (a) the power to invest funds in, and withdraw, make distributions and pay taxes and other obligations owed by the Reorganized Debtors from funds held by the Reorganized Debtor Plan Administrator and/or the Reorganized Debtors in accordance with the Plan, (b) the power to compromise and settle Claims and causes of action on behalf of or against the Reorganized Debtors other than Litigation Trust Claims, Special Litigation Trust Claims and claims and causes of action that are the subject of the Severance Settlement Fund Litigation, and (c) such other powers as may be vested in or assumed by the Reorganized Debtor Plan Administrator pursuant to the Plan, the Reorganized Debtor Plan Administration Agreement or as may be deemed necessary and proper to carry out the provisions of the Plan. Refer to Exhibit 1: "Chapter 11 Plan" for additional information.

2. Role of the Reorganized Debtors

Pursuant to the Plan, as of the Effective Date, the Reorganized Debtors will assist the Reorganized Debtor Plan Administrator in performing the following activities: (a) holding the Operating Entities for the benefit of Creditors and providing certain transition services to such entities, (b) liquidating the Remaining Assets, (c) making distributions to Creditors pursuant to the terms of the Plan, (d) prosecuting Claim objections and litigation, (e) winding up the Debtors' business affairs, and (f) otherwise implementing and effectuating the terms and provisions of the Plan.

3. Establishment and Maintenance of Disbursement Account

On or prior to the Effective Date, the Debtors shall establish one or more segregated bank accounts in the name of the Reorganized Debtors as Disbursing Agent under the Plan, which accounts shall be trust accounts for the benefit of Creditors and holders of Administrative Expense Claims pursuant to the Plan and utilized solely for the investment and distribution of Cash consistent with the terms and conditions of the Plan. On or prior to the Effective Date, and periodically thereafter, the Debtors shall deposit into such Disbursement Account(s) all Cash and Cash Equivalents of the Debtors, less amounts reasonably determined by the Debtors or the Reorganized Debtors, as the case may be, as necessary to fund the ongoing implementation of the Plan and operations of the Reorganized Debtors.

Disbursement Account(s) shall be maintained at one or more domestic banks or financial institutions of the Reorganized Debtors' choice having a shareholder's equity or equivalent capital of not less than $100,000,000.00. The Reorganized Debtors shall invest Cash in Disbursement Account(s) in Cash Equivalents; provided, however, that sufficient liquidity shall be maintained in such account or accounts to (a) make promptly when due all payments upon Disputed Claims if, as and when they become Allowed Claims and (b) make promptly when due the other payments provided for in the Plan.

4. Rights and Powers of the Disbursing Agent

Except to the extent that the responsibility for the same is vested in the Reorganized Debtor Plan Administrator pursuant to the Reorganized Debtor Plan Administration Agreement, the Disbursing Agent shall be empowered to (a) take all steps and execute all instruments and documents necessary to effectuate the Plan, (b) make distributions contemplated by the Plan, (c) comply with the Plan and the obligations thereunder, (d) file all tax returns and pay taxes in connection with the reserves created pursuant to Article XVIII of the Plan, and (e) exercise such other powers as may be vested in the Disbursing Agent pursuant to order of the Bankruptcy Court, pursuant to the Plan, or as deemed by the Disbursing Agent to be necessary and proper to implement the provisions of the Plan.

Except as otherwise ordered by the Bankruptcy Court, the amount of any reasonable fees and expenses incurred by the Disbursing Agent from and after the Effective Date and any reasonable compensation and expense reimbursement claims, including, without limitation, reasonable fees and expenses of counsel, made by the Disbursing Agent, shall be paid in Cash by the Reorganized Debtors without further order of the Bankruptcy Court within fifteen (15) days of submission of an invoice by the Disbursing Agent. In the event that the Reorganized Debtors object to the payment of such invoice for post-Effective Date fees and expenses, in whole or in part, and the parties cannot resolve such objection after good faith negotiation, the Bankruptcy Court shall retain jurisdiction to make a determination as to the extent to which the invoice shall be paid by the Reorganized Debtors.

From and after the Effective Date, the Disbursing Agent shall be exculpated by all Persons and Entities, including, without limitation, holders of Claims and Equity Interests and other parties in interest, from any and all claims, causes of action and other assertions of liability arising out of the discharge of the powers and duties conferred upon such Disbursing Agent by the Plan or any order of the Bankruptcy Court entered pursuant to or in furtherance of the Plan, or applicable law, except for actions or omissions to act arising out of the gross negligence or willful misconduct of such Disbursing Agent. No holder of a Claim or an Equity Interest or other party in interest shall have or pursue any claim or cause of action against the Disbursing Agent for making payments in accordance with the Plan or for implementing the provisions of the Plan.

B. Operating Entities and Trusts

1. Operating Entities

a. PGE

Refer to Section VIII., "Portland General Electric Company" for further information relating to PGE.

(i) Assets. Unless PGE is sold to a third party, the Reorganized Debtors will hold common stock in PGE until (i) such shares of common stock are cancelled and newly issued shares of PGE Common Stock are issued and distributed to the Creditors or an Operating Trust, or (ii) such shares are assigned to a holding company and the holding company's shares are issued and distributed to the Creditors, each in accordance with the Plan.

(ii) Auxiliary Agreements. PGE has entered into a master services agreement with affiliates, including ENE. The PGE MSA allows PGE to provide affiliates with the following general types of services: printing and copying, mail services, purchasing, computer hardware and software support, human resources support, library services, tax and legal services, accounting services, business analyses, purchasing, product development, finance and treasury support, and construction and engineering services. The PGE MSA also allows ENE to provide PGE with the following services: executive oversight, general governance, financial services, human resource support, legal services, governmental affairs service, and public relations and marketing services. PGE services are priced at the higher of fully allocated cost or market (unless specified otherwise) while affiliate services are priced at the lower of cost or market (unless specified otherwise). ENE provides certain employee health and welfare benefits and insurance services to PGE under the PGE MSA that are directly allocated or billed to PGE based upon PGE's usage or the cost for those services. In addition, ENE provides administrative services to PGE under the PGE MSA for a fee equal to the total cost of these services multiplied by an allocation factor based on the Modified Massachusetts Formula (a formula that takes a number of factors into account such as income, assets, and employees). Moreover, PGE provides certain administrative services to ENE and services to certain ENE affiliates under the PGE MSA. The provision of these services is anticipated to continue until such services are replaced, which ENE expects will occur by the end of 2004. ENE, ENE affiliates, and PGE may enter into other arrangements that may extend beyond 2004, subject to Bankruptcy Court approval if such agreements are reached before the Effective Date of the Plan.

(iii) Tax Sharing Agreement. PGE has entered into a tax-sharing arrangement with ENE pursuant to which PGE will be responsible for the amount of income tax that PGE would have paid on a "stand alone" basis, and ENE will be obligated to make payments to PGE as compensation for the use of PGE's losses and/or credits to the extent that such losses and/or credits have reduced the consolidated income tax liability. ENE will be responsible for, among other things, the preparation and filing of all required consolidated returns on behalf of PGE and its subsidiaries, making elections and adopting accounting methods, filing claims for refunds or credits and managing audits and other administrative proceedings conducted by the taxing authorities. After the Effective Date, ENE and PGE may continue to be parties to this tax sharing agreement, or a new agreement on similar terms, until ENE and PGE no longer file consolidated tax returns. It is intended that ENE and PGE will file consolidated tax returns until ENE no longer owns 80% of the capital stock of PGE, which may occur by a sale of PGE stock to a third party or the cancellation of PGE stock held by ENE to issue new stock to the Creditors.

b. CrossCountry

Refer to Section IX., "CrossCountry Energy Corp." for further information relating to CrossCountry.

(i) Assets. Unless CrossCountry is sold to a third party, the Reorganized Debtors will hold common stock in CrossCountry until (i) such shares are cancelled and shares of CrossCountry Common Stock are issued to the Creditors or an Operating Trust, or (ii) such shares are assigned to a holding company and the holding company's shares are issued to the Creditors, each in accordance with the Plan. If the Debtors and the Creditors' Committee, in their joint and absolute discretion, determine to issue preferred stock of CrossCountry (or one of the alternative entities formed pursuant to Section 37.3 of the Plan) and such preferred stock is issued subsequent to the Confirmation Date and prior to the issuance of the CrossCountry Common Stock pursuant to the Plan, such preferred stock will not be cancelled. Refer to Section IX.F.1.c., "Implementation of CrossCountry Contribution and Separation Agreement".

(ii) Auxiliary Agreements. The Reorganized Debtors anticipate providing transition services, including administrative operation management, through approximately December 31, 2004. Refer to Section IX.F.1., "Formation of CrossCountry" for further information.

(iii) Tax Sharing Agreement. In conjunction with the formation and implementation of CrossCountry, CrossCountry, Northern Plains, Pan Border, NBP Services, Transwestern Holding, Transwestern and CrossCountry Citrus Corp. will enter into a Tax Sharing Agreement with ENE. The Tax Sharing Agreement will set forth the respective rights and responsibilities of the parties to the agreement with respect to taxes. For additional information, refer to Section IX.F.1.b(iii)., "Tax Sharing Agreement".

c. Prisma

Refer to Section X., "Prisma Energy International Inc." for further information relating to Prisma.

(i) Assets. Unless Prisma is sold to a third party, the Reorganized Debtors will hold common stock in Prisma until such shares are cancelled and newly issued shares of Prisma Common Stock are distributed to the Creditors or an Operating Trust in accordance with the Plan.

(ii) Auxiliary Agreements. The Reorganized Debtors anticipate providing and receiving transition services to and from Prisma (including administrative and other support services, through a date to be determined) and may enter into other arrangements. The current transition services agreement is scheduled to expire upon the earlier of December 31, 2005 or, for each asset which transition services are provided, shortly after transfer of the asset to Prisma, a Prisma subsidiary, or a third party. Refer to Section X.A.3.b., "Formation of Prisma and Contribution of Prisma Assets" for further information.

(iii) Tax Sharing Agreement. The Reorganized Debtors anticipate entering into a Tax Sharing Agreement with Prisma and its subsidiaries.

2. Operating Trusts

Notwithstanding the foregoing, upon joint determination of the Debtors and the Creditors' Committee, the shares of PGE Common Stock, CrossCountry Common Stock, and

Prisma Common Stock will be transferred to the holders of certain Allowed Claims, which will be held by the Debtors acting on their behalf. Immediately thereafter, on behalf of the holders of such Allowed Claims, the Debtors shall transfer such shares, subject to the Operating Trust Agreements, to the Operating Trusts for the benefit of the holders of such Allowed Claims in accordance with the Plan. Refer to Exhibit 1: "Chapter 11 Plan" for further information.

a. Establishment of the Trusts. On or after the Confirmation Date, but prior to the Effective Date, and upon the joint determination of the Debtors and the Creditors' Committee, the Debtors, on their own behalf and on behalf of holders of Allowed Claims in Classes 3 through 180, 183 through 189, and 376 through 382, shall execute the respective Operating Trust Agreements and shall take all other steps necessary to establish the respective Operating Trusts. On such date, or as soon as practicable thereafter, including, without limitation, subject to appropriate or required governmental, agency or other consents, and in accordance with and pursuant to the terms of Section 24.4 of the Plan, the Debtors shall transfer to the respective Operating Trusts all of their right, title, and interest in the assets subject to the Operating Trust Agreements.

b. Purpose of the Operating Trusts. The Operating Trusts shall be established for the sole purpose of holding and liquidating the respective assets in the PGE Trust, the CrossCountry Trust, and the Prisma Trust in accordance with Treasury Regulation Section 301.7701-4(d) and the terms and provisions of the Operating Trust Agreements. Without limiting the foregoing, the Operating Trust Agreements shall each provide that the applicable Operating Trust shall not distribute any of the PGE Common Stock, CrossCountry Common Stock, or Prisma Common Stock, as the case may be, prior to the date referred to in Sections 32.c.1.(c) (i), (ii) and (iii) of the Plan.

c. Funding Expenses of the Operating Trusts. In accordance with the respective Operating Trust Agreements and any agreements entered into in connection therewith, on the Effective Date, the Debtors shall have no obligation to provide any funding with respect to any of the Operating Trusts.

d. Transfer of Assets

(i) The transfer of assets to the Operating Trusts shall be made, as provided in the Plan, for the benefit of the holders of Allowed Claims in Classes 3 through 180, 183 through 189, and 376 through 382, only to the extent such holders in such Classes are entitled to distributions under the Plan. In partial satisfaction of Allowed Claims in Classes 3 through 180, 183 through 189, and 376 through 382, the assets subject to the respective Operating Trusts shall be transferred to such holders of Allowed Claims, to be held by the Debtors on their behalf. Immediately thereafter, on behalf of the holders of Allowed Claims in Classes 3 through 180, 183 through 189, and 376 through 382, the Debtors shall transfer such assets to the Operating Trusts for the benefit of holders of Allowed Claims in Classes 3 through 180, 183 through 189, and 376 through 382, in accordance with the Plan.

(ii) For all federal income tax purposes, all parties (including, without limitation, the Debtors, the Operating Trustee and the beneficiaries of the Operating Trusts) shall treat the transfer of assets to the respective Operating Trusts in

accordance with the terms of the Plan, as a transfer to the holders of Allowed Claims in Classes 3 through 180, 183 through 189, and 376 through 382, followed by a transfer by such holders to the respective Operating Trusts and the beneficiaries of the Operating Trusts shall be treated as the grantors and owners thereof.

e. Valuation of Assets. As soon as possible after the Effective Date, but in no event later than thirty (30) days thereafter, the respective Operating Trust Boards shall inform, in writing, the Operating Trustee of the value of the assets transferred to the respective Operating Trusts, based on the good faith determination of the respective Operating Trust Boards, and the Operating Trustee shall apprise, in writing, the beneficiaries of the respective Operating Trusts of such valuation. The valuation shall be used consistently by all parties (including the Debtors, the Reorganized Debtors, the Operating Trustee, and the beneficiaries of the Operating Trusts) for all federal income tax purposes.

f. Investment Powers. The right and power of the Operating Trustee to invest assets transferred to the Operating Trusts, the proceeds thereof, or any income earned by the respective Operating Trusts, shall be limited to the right and power to invest such assets (pending periodic distributions in accordance with Section 24.7 of the Plan) in Cash Equivalents; provided, however, that (a) the scope of any such permissible investments shall be limited to include only those investments, or shall be expanded to include any additional investments, as the case may be, that a liquidating trust, within the meaning of Treasury Regulation Section 301.7701-4(d) may be permitted to hold, pursuant to the Treasury Regulations, or any modification in the IRS guidelines, whether set forth in IRS rulings, other IRS pronouncements or otherwise, and (b) the Operating Trustee may expend the assets of the Operating Trusts (i) as reasonably necessary to meet contingent liabilities and to maintain the value of the assets of the Operating Trusts during liquidation, (ii) to pay reasonable administrative expenses (including, but not limited to, any taxes imposed on the Operating Trusts or fees and expenses in connection with litigation), and (iii) to satisfy other liabilities incurred or assumed by the Operating Trusts (or to which the assets are otherwise subject) in accordance with the Plan or the Operating Trust Agreements; and, provided, further, that, under no circumstances, shall the Operating Trusts segregate the assets of the Operating Trusts on the basis of classification of the holders of respective Operating Trust Interests, other than with respect to distributions to be made on account of Disputed Claims and Disputed Equity Interests in accordance with the provisions of the Plan.

g. Annual Distribution; Withholding. The Operating Trustee shall distribute at least annually to the holders of respective Operating Trust Interests all net cash income plus all net cash proceeds from the liquidation of assets (including as Cash for this purpose, all Cash Equivalents); provided, however, that the Operating Trusts may retain such amounts (i) as are reasonably necessary to meet contingent liabilities and to maintain the value of the assets of the Operating Trusts during liquidation, (ii) to pay reasonable administrative expenses (including any taxes imposed on the Operating Trusts or in respect of the assets of the Operating Trust), and (iii) to satisfy other liabilities incurred or assumed by the Operating Trusts (or to which the assets are otherwise subject) in accordance with the Plan or the Operating Trust Agreements. All such distributions shall be pro rata based on the number of Operating Trust Interests held by a holder compared with the aggregate number of Operating Trust Interests outstanding, subject to the terms of the Plan and the respective Operating Trust Agreements.

The Operating Trustee may withhold from amounts distributable to any Person any and all amounts, determined in the Operating Trustee's reasonable sole discretion, to be required by any law, regulation, rule, ruling, directive, or other governmental requirement.

h. Reporting Duties

(i) Federal Income Tax. Subject to definitive guidance from the IRS or a court of competent jurisdiction to the contrary (including the receipt by the Operating Trustee of a private letter ruling if the Operating Trustee so requests one, or the receipt of an adverse determination by the IRS upon audit if not contested by the Operating Trustee), the Operating Trustee shall file returns for the Operating Trusts as a grantor trust pursuant to Treasury Regulation Section 1.671-4(a). The Operating Trustee shall also annually send to each holder of a Operating Trust Interest a separate statement setting forth the holder's share of items of income, gain, loss, deduction, or credit and shall instruct all such holders to report such items on their federal income tax returns.

(ii) Allocations of Operating Trusts Taxable Income. Allocations of Operating Trust taxable income shall be determined by reference to the manner in which an amount of cash equal to such taxable income would be distributed (without regard to any restrictions on distributions described in the Plan) if, immediately prior to such deemed distribution, the Operating Trust had distributed all of its other assets (valued for this purpose at their tax book value) to the holders of the Operating Trust Interests (treating any holder of a Disputed Claim, for this purpose, as a current holder of a Operating Trust Interest entitled to distributions), taking into account all prior and concurrent distributions from the Operating Trusts (including all distributions held in escrow pending the resolution of Disputed Claims). Similarly, taxable loss of the Operating Trusts shall be allocated by reference to the manner in which an economic loss would be borne immediately after a liquidating distribution of the remaining assets of an Operating Trust. The tax book value of the assets of an Operating Trust for this purpose shall equal their fair market value on the date such Operating Trusts were created or, if later, the date such assets were acquired by the Operating Trust, adjusted in either case in accordance with tax accounting principles prescribed by the IRC, the regulations, and other applicable administrative and judicial authorities and pronouncements.

(iii) Other. The Operating Trustee shall file (or cause to be filed) any other statements, returns or disclosures relating to the Operating Trusts that are required by any governmental unit.

i. Trust Implementation. On or after the Confirmation Date, but prior to the Effective Date, the Operating Trusts shall be established and become effective for the benefit of Allowed Claims in Classes 3 through 180, 183 through 189, and 376 through 382. The Operating Trust Agreements shall be filed in the Plan Supplement and shall contain provisions customary to trust agreements utilized in comparable circumstances, including, but not limited to, any and all provisions necessary to ensure the continued treatment of the Operating Trusts as grantor trusts for federal income tax purposes. All parties (including the Debtors, the Operating Trustee and holders of Allowed Claims in Classes 3 through 180, 183 through 189, and 376 through 382) shall execute any documents or other instruments as necessary to cause title to the applicable assets to be transferred to the Operating Trusts.

j. Registry of Beneficial Interests. The Operating Trustee shall maintain a registry of the holders of Operating Trust Interests.

k. Termination. The Operating Trusts shall terminate no later than the third (3rd) anniversary of the Confirmation Date; provided, however, that, on or prior to the date three (3) months prior to such termination, the Bankruptcy Court, upon motion by a party in interest, may extend the term of the Operating Trusts if it is necessary to the liquidation of the assets of Operating Trusts. Notwithstanding the foregoing, multiple extensions can be obtained so long as Bankruptcy Court approval is obtained at least three (3) months prior to the expiration of each extended term; provided, however, that the aggregate of all such extensions shall not exceed three (3) years from and after the third (3rd) anniversary of the Confirmation Date.

l. Non-Transferability or Certification. Upon the creation of each Operating Trust, the beneficial interests in such Operating Trust shall be allocated on the books and records of such Operating Trust to the appropriate holders thereof, but such interests shall not be certificated and shall not be transferable by the holder thereof except through the laws of descent or distribution.

C. Remaining Assets

1. Categories of Remaining Assets

It is anticipated that the Reorganized Debtors will retain all assets that will not be transferred to the Litigation Trust, Special Litigation Trust, Severance Settlement Fund Trust, Operating Trusts, or Operating Entities. These Remaining Assets may include, but are not limited to, Cash, claims and causes of action against third parties on behalf of the Debtors' estates (including, but not limited to, avoidance actions), proceeds of liquidated assets, the Debtors' stock in the Enron Companies, trading contracts, equity investments, inventory, real property, and other miscellaneous assets.

The Reorganized Debtor Plan Administrator, with assistance from the Reorganized Debtors, will collect and liquidate the Remaining Assets and distribute the proceeds to Creditors pursuant to the terms of the Plan. The board of directors of the Reorganized Debtors will supervise this process. Poor market conditions, litigation, and complex ownership structures may result in the retention of certain assets for an extended period of time. As a result, the Reorganized Debtors and the Reorganized Debtor Plan Administrator will continue to manage and operate these assets until a favorable sale or resolution of each of the Remaining Assets is finalized. Refer Section XIV., "Risk Factors and Other Factors to be Considered" for a discussion of the risks related to the Reorganized Debtors.

The following provides a brief description of the Remaining Assets:

a. Creditor Cash. The Enron Companies have received a significant amount of Cash as a result of asset sales and the liquidation of the wholesale and retail trading books during the Chapter 11 Cases. The postpetition Cash collected to date plus the Cash collected by the Reorganized Debtors as part of their future liquidation efforts will be distributed by the Reorganized Debtor Plan Administrator in accordance with the Plan after the satisfaction of certain obligations, including Administrative Expense Claims, Priority Non-Tax Claims, Priority Tax Claims, Convenience Claims, Secured Claims, funds necessary to operate the Litigation Trust and Special Litigation Trust, funds necessary to make pro rata distributions to holders of Disputed Claims as if such Disputed Claims were, at such time, Allowed Claims, and funds necessary for the ongoing operations of the Reorganized Debtors from the Effective Date until such later date as reasonably determined by the Reorganized Debtor Plan Administrator.

b. Trading Contracts

(i) Wholesale Trading. As described in Section IV.B.1., "Resolution of the Wholesale Trading Book", the Wholesale Services Debtors and certain of their non-Debtor Wholesale Services affiliates have undertaken efforts to perform, sell, or settle a significant number of non-terminated and terminated positions arising out of Wholesale Contracts.

As of October 31, 2003, the Wholesale Services Debtors and certain of their non-Debtor Wholesale Services affiliates had Wholesale Contracts with approximately 1,285 counterparty groups totaling approximately $933 million of expected recoverable value. Substantially all of the collections and cash settlements of Wholesale Contracts are expected to be resolved prior to the Effective Date. Those Wholesale Contracts that cannot be settled are either currently in or may require litigation in order to collect outstanding balances. Any recovery from such litigation involving a Debtor will be included in the Remaining Assets available for subsequent distribution.

(ii) Retail Trading. As described in Section IV.B.2., "Retail Contract Settlements" the Retail Services Debtors and their non-Debtor Retail Services affiliates have undertaken efforts to perform, sell, settle, or reject a significant number of non-terminated and terminated positions arising out of Retail Contracts.

As of October 31, 2003, the Retail Services Debtors and certain of their non-Debtor Retail Services affiliates had Retail Contracts with approximately 9,800 counterparty groups totaling approximately $102.1 million of expected recoverable value.

The Debtors are attempting to settle each of the Retail Contracts on a case-by-case basis, with the largest accounts taking priority. If the Debtors are unable to collect, or reach a settlement on, these contracts, the Debtors or Reorganized Debtor Plan Administrator may initiate litigation in order to collect outstanding balances.

c. Other Recoveries

(i) Recoveries in PG&E Bankruptcy. A significant portion of the balances owed in retail trading involves claims that ENE has in PG&E's bankruptcy. There is uncertainty around the collection of these claims; however, ENE has undertaken settlement negotiations with PG&E.

(ii) Recoveries from European Estates. A significant amount of money is due from the sale of assets of ENE's direct and indirect European subsidiaries under UK administration. The administrator in the UK process is responsible for selling assets and, under a Scheme of Arrangement, will make distributions to creditors and, when applicable, equity security holders. There is uncertainty regarding the amount, timing and frequency of any distributions to be made to the Debtors or the Reorganized Debtors. Refer to Section V., "Certain International Subsidiaries and Related International Proceedings" for further information.

d. Remaining Assets Currently Available For Sale. As of September 30, 2003, the Debtors and certain of their non-Debtor affiliates had identified approximately 210 assets available for sale with an expected recovery to the Debtors' estates totaling approximately $1.1 billion. These assets include direct or indirect ownership and/or operation of businesses and investments related to a variety of industries, including paper production, oil and gas exploration and production, power generation, intrastate natural gas pipeline operations, natural gas pipeline compression services and energy and telecommunications-related technology businesses. The balance of the assets is made up of miscellaneous assets, including: contingent receivables, inventory, real property, insurance and emissions credits.

The Reorganized Debtor Plan Administrator, with supervision from the board of directors of the Reorganized Debtors, will continue to monitor market conditions and identify when there is sufficient interest in a particular asset to pursue a sale. Priority will be given to the assets with the greatest potential recoverable value; however, many of these sales efforts may be delayed due to regulatory issues, ownership through SPEs, or litigation.

The assets with more significant expected recoveries to the Debtors' estates are listed below:

(i) CPS and St. Aurelie Timberlands Co. Ltd. 100% interest in a 500,000 tonne/year newsprint, directory paper and paperboard mill in Quebec City, Quebec, Canada along with a sawmill and timberlands in Quebec and timberlands in Maine. The Debtors have executed an asset purchase agreement with a potential purchaser and anticipate that CPS and St. Aurelie Timberlands will be sold pursuant to an auction process that is currently underway. Bids for the assets are due in early November 2003. Refer to Section I.B.2.d., "Asset Ownership Disputes Between ENE and ENA" for information relating to ownership disputes involving CPS and Section IV.C.1.f(iii)(A)., "Mizuho Corporate Bank, Ltd., as successor to the Industrial Bank of Japan, Limited and Banco Bilbao Vizcaya Argentaria S.A. v. Enron Corp. Hansen Investments Co. and Compagnie Papiers Stadacona" for more information relating to settlement of the Mizuho litigation related to CPS.[38]

(ii) Sithe Sub Debt. SIPP, a non-Debtor affiliate, owns a 1,042-MW power plant in western New York. SIPP's primary revenue contracts are a power purchase contract with ConEd (approximately 61% of revenues) and a tolling agreement with Dynegy (approximately 33% of revenues). As a result of a series of transactions that closed June 30, 2001, ENA owns two investments in SIPP. The two investments are (1) 40% of SIPP's partnership interest and (2) approximately $419 million in subordinated debt that matures in

[38] The Debtors have executed an asset purchase agreement relating to CPS. The CPS sale has not yet been approved by the Bankruptcy Court and is subject to an auction process. There can be no guarantee as to the outcome of this process, nor can the Debtors guarantee that the Bankruptcy Court will approve the proposed sale.

2034, and requires semi-annual interest payments of 7% to ENA (the payments are interest only through 2015).[39]

(iii) Bridgeline. Bridgeline Holdings is a limited partnership that was formed by ENA and TEPI to aggregate approximately 1,000 miles of mainline intrastate natural gas pipeline and 13 bcf of working gas storage capacity in Louisiana. Certain Enron Affiliates collectively own a 40% LP interest in Bridgeline Holdings. The general partner of Bridgeline Holdings is Bridgeline LLC, which is equally controlled by ENA and TEPI subsidiaries. Refer to Section I.B.2.d., "Asset Ownership Disputes Between ENE and ENA" for further information relating to ownership disputes involving Bridgeline Holdings.

(iv) Financial Swap. A JEDI II wholly owned subsidiary sold the majority of its remaining equity interest in a venture in early 2001. Pursuant to the sale, the JEDI II subsidiary receives scheduled quarterly payments commencing May 15, 2001 and ending February 15, 2008. The payments are guaranteed by a non-investment grade affiliate of the payor. It is anticipated that JEDI II will either (1) retain the quarterly payments through February 2008, (2) monetize the quarterly payments or (3) exchange the quarterly payments with the payment's guarantor for a readily marketable security

(v) Enron Compression Services. Enron Compression Services promotes the utilization of electric motor drive systems in association with natural gas compression applications. It manages and operates five compressor stations for Transwestern, Florida Gas, and NNG.

(vi) ServiceCo. ServiceCo provides HVAC (heating, ventilation, and air conditioning) services and full building facility services to commercial customers nationwide. ENE has a 65.8% equity interest in ServiceCo. Refer to Section IV.B.4.e., "Redemption of ServiceCo Shares".

(vii) Mariner. Mariner is a privately held exploration and production company that focuses its exploration in the deepwater and shelf areas of the Gulf of Mexico. Excluding Falcon Corridor reserves that were sold in March 2003, Mariner had total proved reserves of 167.5 bcf equivalents as of December 31, 2002, of which 60% was natural gas and 40% was oil and condensate. ENE indirectly owns a 95.7% (89.9% fully diluted) equity interest in Mariner. Mariner Energy LLC, the parent entity of Mariner, has a $164.4 million term loan (as of December 31, 2002) that bears interest at 15%. Such debt will materially reduce net recoverable value of Mariner equity to the ENE estate.

2. The Remaining Asset Trusts

Notwithstanding the foregoing, upon joint determination of the Debtors and the Creditors' Committee, the Debtors' interests in the Remaining Assets will be transferred to the holders of certain Allowed Claims, which will be held by the Debtors acting on their behalf.

[39] The Debtors have executed an asset purchase agreement relating to Sithe. The Sithe sale has not yet been approved by the Bankruptcy Court and is subject to an auction process. There can be no guarantee as to the outcome of this process, nor can the Debtors guarantee that the Bankruptcy Court will approve the proposed sale.

Immediately thereafter, on behalf of the holders of such Allowed Claims, the Debtors shall transfer such assets, subject to the Remaining Asset Trust Agreements, to the Remaining Asset Trusts for the benefit of the holders of such Allowed Claims in accordance with the Plan. Refer to Appendix L: "Liquidation Analysis" for further information.

a. Establishment of the Trusts. On or after the Confirmation Date, but prior to the Effective Date, and upon the joint determination of the Debtors and the Creditors' Committee, the Debtors, on their own behalf and on behalf of holders of Allowed Claims in Classes 3 through 180, 183 through 189, and 376 through 382, shall execute the respective Remaining Asset Trust Agreements and shall take all other steps necessary to establish the respective Remaining Asset Trusts. On such date, or as soon as practicable thereafter, including, without limitation, subject to appropriate or required governmental agency or other consents, and in accordance with and pursuant to the terms of Section 25.4 of the Plan, the Debtors shall transfer to the respective Remaining Asset Trusts all of their right, title, and interest in the Remaining Assets.

b. Purpose of the Remaining Asset Trusts. The Remaining Asset Trusts shall be established for the sole purpose of holding and liquidating the respective assets in the Remaining Asset Trusts in accordance with Treasury Regulation Section 301.7701-4(d) and the terms and provisions of the Remaining Asset Trust Agreements.

c. Funding Expenses of the Remaining Asset Trusts. In accordance with the respective Remaining Asset Trust Agreements and any agreements entered into in connection therewith, on the Effective Date, the Debtors shall have no obligation to provide any funding with respect to any of the Remaining Asset Trusts.

d. Transfer of Assets

(i) The transfer of assets to the Remaining Asset Trusts shall be made, as provided in the Plan, for the benefit of the holders of Allowed Claims in Classes 3 through 180, 183 through 189 and 376 through 382, only to the extent such holders in such Classes are entitled to distributions under the Plan. In partial satisfaction of Allowed Claims in Classes 3 through 180, 183 through 189 and 376 through 382, the Remaining Assets shall be transferred to such holders of Allowed Claims, to be held by the Debtors on their behalf. Immediately thereafter, on behalf of the holders of Allowed Claims in Classes 3 through 180, 183 through 189 and 376 through 382, the Debtors shall transfer such assets to the Remaining Asset Trusts for the benefit of holders of Allowed Claims in Classes 3 through 180, 183 through 189 and 376 through 382, in accordance with the Plan. Upon the transfer of the Remaining Assets, the Debtors shall have no interest in or with respect to the Remaining Assets or the Remaining Asset Trusts.

(ii) For all federal income tax purposes, all parties (including, without limitation, the Debtors, the Remaining Asset Trustee, and the beneficiaries of the Remaining Asset Trusts) shall treat the transfer of assets to the respective Remaining Asset Trusts in accordance with the terms of the Plan, as a transfer to the holders of Allowed Claims in Classes 3 through 180, 183 through 189 and 376 through 382, followed by a

transfer by such holders to the Remaining Asset Trust and the beneficiaries of the respective Remaining Asset Trusts shall be treated as the grantors and owners thereof.

e. Valuation of Assets. As soon as possible after the Effective Date, but in no event later than thirty (30) days thereafter, the respective Remaining Asset Trust Boards shall inform, in writing, the Remaining Asset Trustees of the value of the assets transferred to the respective Remaining Asset Trusts, based on the good faith determination of the respective Remaining Asset Trust Boards, and the Remaining Asset Trustees shall apprise, in writing, the beneficiaries of the respective Remaining Asset Trusts of such valuation. The valuation shall be used consistently by all parties (including the Debtors, the Reorganized Debtors, the Remaining Asset Trustees, and the beneficiaries of the Remaining Asset Trusts) for all federal income tax purposes.

f. Investment Powers. The right and power of the Remaining Asset Trustee to invest assets transferred to the Remaining Asset Trusts, the proceeds thereof, or any income earned by the respective Remaining Asset Trusts, shall be limited to the right and power to invest such assets (pending periodic distributions in accordance with Section 25.7 of the Plan) in Cash Equivalents; provided, however, that (a) the scope of any such permissible investments shall be limited to include only those investments, or shall be expanded to include any additional investments, as the case may be, that a liquidating trust, within the meaning of Treasury Regulation Section 301.7701-4(d) may be permitted to hold, pursuant to the Treasury Regulations, or any modification in the IRS guidelines, whether set forth in IRS rulings, other IRS pronouncements or otherwise, and (b) the Remaining Asset Trustee may expend the assets of the Remaining Asset Trusts (i) as reasonably necessary to meet contingent liabilities and to maintain the value of the assets of the Remaining Asset Trusts during liquidation, (ii) to pay reasonable administrative expenses (including, but not limited to, any taxes imposed on the Remaining Asset Trusts or fees and expenses in connection with litigation), and (iii) to satisfy other liabilities incurred or assumed by the Remaining Asset Trusts (or to which the assets are otherwise subject) in accordance with the Plan or the Remaining Asset Trust Agreements; and, provided, further, that, under no circumstances, shall the Remaining Asset Trustee segregate the assets of the Remaining Asset Trust on the basis of classification of the holders of Remaining Asset Trust Interests, other than with respect to distributions to be made on account of Disputed Claims and Disputed Equity Interests in accordance with the provisions of the Plan.

g. Annual Distribution; Withholding. The Remaining Asset Trustee shall distribute at least annually to the holders of Remaining Asset Trust Interests all net cash income plus all net cash proceeds from the liquidation of assets (including as Cash for this purpose, all Cash Equivalents); provided, however, that the Remaining Asset Trusts may retain such amounts (i) as are reasonably necessary to meet contingent liabilities and to maintain the value of the assets of the Remaining Asset Trusts during liquidation, (ii) to pay reasonable administrative expenses (including any taxes imposed on the Remaining Asset Trust or in respect of the assets of the Remaining Asset Trusts), and (iii) to satisfy other liabilities incurred or assumed by the Remaining Asset Trusts (or to which the assets are otherwise subject) in accordance with the Plan or the Remaining Asset Trust Agreements. All such distributions shall be pro rata based on the number of Remaining Asset Trust Interests held by a holder compared with the aggregate number of Remaining Asset Trust Interests outstanding, subject to the terms of the Plan and the Remaining Asset Trust Agreements. The Remaining Asset Trustee may withhold from amounts distributable to any Person any and all amounts, determined in the Remaining Asset Trustee's reasonable sole discretion, to be required by any law, regulation, rule, ruling, directive, or other governmental requirement.

h. Reporting Duties

(i) Federal Income Tax. Subject to definitive guidance from the IRS or a court of competent jurisdiction to the contrary (including the receipt by the Remaining Asset Trustee of a private letter ruling if the Remaining Asset Trustee so requests one, or the receipt of an adverse determination by the IRS upon audit if not contested by the Remaining Asset Trustee), the Remaining Asset Trustee shall file returns for the Remaining Asset Trusts as a grantor trust pursuant to Treasury Regulation Section 1.671-4(a). The Remaining Asset Trustee shall also annually send to each holder of a Remaining Asset Trust Interest a separate statement setting forth the holder's share of items of income, gain, loss, deduction or credit and shall instruct all such holders to report such items on their federal income tax returns.

(ii) Allocations of Remaining Asset Trust Taxable Income. Allocations of Remaining Asset Trust taxable income shall be determined by reference to the manner in which an amount of cash equal to such taxable income would be distributed (without regard to any restrictions on distributions described in the Plan) if, immediately prior to such deemed distribution, the Remaining Asset Trust had distributed all of its other assets (valued for this purpose at their tax book value) to the holders of the Remaining Asset Trust Interests (treating any holder of a Disputed Claim, for this purpose, as a current holder of a Remaining Asset Trust Interest entitled to distributions), taking into account all prior and concurrent distributions from the Remaining Asset Trust (including all distributions held in escrow pending the resolution of Disputed Claims). Similarly, taxable loss of the Remaining Asset Trusts shall be allocated by reference to the manner in which an economic loss would be borne immediately after a liquidating distribution of the remaining Remaining Asset Trust Assets. The tax book value of the Remaining Asset Trust Assets for this purpose shall equal their fair market value on the date such Remaining Assets Trusts were created or, if later, the date such assets were acquired by the Remaining Asset Trusts, adjusted in either case in accordance with tax accounting principles prescribed by the IRC, the regulations and other applicable administrative and judicial authorities and pronouncements.

(iii) Other. The Remaining Asset Trustee shall file (or cause to be filed) any other statements, returns, or disclosures relating to the Remaining Asset Trusts that are required by any governmental unit.

i. Trust Implementation. On or after the Confirmation Date, but prior to the Effective Date, the Remaining Asset Trusts will be established and become effective for the benefit of Allowed Claims in Classes 3 through 180, 183 through 189 and 376 through 382. The Remaining Asset Trust Agreements shall be filed in the Plan Supplement and shall contain provisions customary to trust agreements utilized in comparable circumstances, including, but not limited to, any and all provisions necessary to ensure the continued treatment of the Remaining Asset Trusts as grantor trusts for federal income tax purposes. All parties (including the Debtors, the Remaining Asset Trustee, and holders of Allowed Claims in Classes 3 through

180, 183 through 189 and 376 through 382) shall execute any documents or other instruments as necessary to cause title to the applicable assets to be transferred to the Remaining Asset Trusts.

j. Registry of Beneficial Interests. The Remaining Asset Trustee shall maintain a registry of the holders of Remaining Asset Trust Interests.

k. Termination. The Remaining Asset Trusts shall terminate no later than the third (3rd) anniversary of the Confirmation Date; provided, however, that, on or prior to the date three (3) months prior to such termination, the Bankruptcy Court, upon motion by a party in interest, may extend the term of the Remaining Asset Trusts if it is necessary to the liquidation of the Remaining Asset Trust Assets. Notwithstanding the foregoing, multiple extensions can be obtained so long as Bankruptcy Court approval is obtained at least three (3) months prior to the expiration of each extended term; provided, however, that the aggregate of all such extensions shall not exceed three (3) years from and after the third (3rd) anniversary of the Confirmation Date.

l. Non-Transferability or Certification. Upon the creation of the Remaining Asset Trusts, the Remaining Asset Trust Interests shall be allocated on the books and records of the Remaining Asset Trusts to the appropriate holders thereof, but the Remaining Asset Trust Interests shall not be certificated and shall not be transferable by the holder thereof except through the laws of descent or distribution; provided, however, that the deemed recipient thereof may hold such Remaining Asset Trust Interests through a single wholly owned Entity.

D. Other Administration

1. Claims Processing

The Reorganized Debtors will be responsible for processing all Claims that have been filed against the Debtors. More than 24,000 claims have been filed in the Debtors Chapter 11 Cases (32% are employee claims, 16% are non-trading accounts payable claims, 16% are trading–related payables and contract claims, 13% are litigation and non-trading contract claims, 10% are common and preferred equity claims, and 13% are other claims). Refer to Section XVII., "Claims Allowance, Objection and Estimation Procedures" for further information regarding Claims.

2. Legal Entities

On the Initial Petition Date, the Enron Companies totaled approximately 2,400 legal entities. Approximately 750 entities have been sold, merged, or dissolved and approximately 1,650 legal entities remain. Refer to Appendix R: "Dissolved Entities Through October 31, 2003" for a list of entities that have been or are being dissolved as of the Initial Petition Date through October 31, 2003. As part of the efforts to wind up the Debtors' business affairs, the Reorganized Debtors intend to dissolve, sell or otherwise dispose of all wholly owned direct and indirect subsidiaries other than the Operating Entities. To date, the Debtors have dissolved, under available state law dissolution processes, non-Debtor affiliates when such dissolution (a) involved a non-Debtor affiliate with no ongoing business and (b) resulted in a reduction of administrative expenses. The Debtors intend to continue to use state law dissolution processes to accomplish these dissolutions. By the end of 2004, it is anticipated that all legal entities will be reduced to those necessary for the Operating Entities and the liquidation of the Remaining Assets. At the time that legal entities are sold or dissolved, their associated shares will be sold, surrendered, or otherwise disposed of. At present, the Debtors do not intend to commence bankruptcy proceedings for the remaining legal entities, however, the Debtors reserve the right, as necessary, to exercise their fiduciary duty to maximize the value of their estates and thereby elect to liquidate, sell or otherwise dispose of any legal entity remaining outside of the Operating Entities by commencing bankruptcy proceedings in the United States or any other jurisdiction deemed appropriate.

3. Prosecuting Claim Objections and Litigation

Except with respect to the Litigation Trust Claims, the Special Litigation Trust Claims, and the Severance Settlement Fund Litigation, from and after the Effective Date, the Reorganized Debtors shall, as a representative of the estates of the Debtors, litigate any claims or causes of action that constituted or could result in recovery of Assets of the Debtors or Debtors in Possession, including, without limitation, any avoidance or recovery actions under sections 541, 544, 545, 547, 548, 549, 550, 551 and 553 of the Bankruptcy Code and any other causes of action, rights to payments of claims that may be pending on the Effective Date or instituted by the Debtors or Debtors in Possession thereafter, to a Final Order, and the Reorganized Debtors may compromise and settle such claims, without approval of the Bankruptcy Court. The net proceeds of any such litigation or settlement (after satisfaction of all costs and expenses incurred in connection therewith) shall be remitted to the Disbursing Agent for (i) allocation to the Debtor that owned such Asset and (ii) distribution in accordance with the Distributive Assets, ACFI Guaranty Distributive Assets, ENA Guaranty Distributive Assets, EPC Guaranty Distributive Assets, Enron Guaranty Distributive Assets, or Wind Guaranty Distributive Assets, as the case may be, attributable to such Debtor; provided, however, that, to the extent that such litigation is commenced by two or more Debtors, the net proceeds of any such litigation or settlement (after satisfaction of all costs and expenses incurred in connection therewith) shall be allocated equally among each of the plaintiffs thereto.

4. Compromise of Certain Guaranty Claim Litigation

Notwithstanding the provisions of Section 28.1 of the Plan, in the event that (a) a holder of a Guaranty Claim maintains a Claim arising from or relating to a guaranty executed during the period from December 2, 2000 up to and including December 2, 2001 and (b) the Debtors have commenced litigation to avoid the incurrence of such guaranty obligation and disallow such Guaranty Claim as a constructive fraudulent conveyance or transfer, the holder of such Guaranty Claim may elect to compromise and settle such litigation in accordance with the following schedule, subject to allowance of such Claim:

Percentage Discount to Allowed Guaranty Claim	Date of Execution
60.0%	01/01/01 – 01/31/01
62.5%	02/01/01 – 02/28/01
65.0%	03/01/01 – 03/31/01
67.5%	04/01/01 – 04/30/01
70.0%	05/01/01 – 05/31/01
72.5%	06/01/01 – 06/30/01
75.0%	07/01/01 – 07/31/01
77.5%	08/01/01 – 08/31/01
80.0%	09/01/01 – 09/30/01
82.5%	10/01/01 – 10/31/01
85.0%	11/01/01 – 12/01/01

Such election must be made on the Ballot and be received by the Debtors on or prior to the Ballot Date. Any election made after the Ballot Date shall not be binding upon the Debtors unless the Ballot Date is expressly waived, in writing, by the Debtors; provided, however, that, under no circumstances, may such waiver by the Debtors occur on or after the Effective Date.

5. Extinguishment of Certain Claims

Except with regard to the allowance of Intercompany Claims in accordance with Sections 2.1 and 15.1 of the Plan, on the Effective Date, each Debtor and Debtor in Possession, other than the Portland Debtors, shall waive and forever release any right, claim or cause of action which could have been asserted by such Debtor or Debtor in Possession against any other Debtor or Debtor in Possession, other than the Portland Debtors, including pursuant to principles of substantive consolidation, piercing the corporate veil, alter ego, domination, constructive trust and similar principles of state or federal creditors' rights laws, and such rights, claims and causes of action shall be extinguished even if otherwise assertable by parties other than the Debtor or Debtors in Possession had the Chapter 11 Cases not been commenced.

6. Budget

Post-confirmation, the Debtors and Reorganized Debtors are expected to incur significant expenses as a result of the wind up of their respective estates. Those expenses include operating expenses, litigation expenses, and professional fees. The Debtors' and Reorganized Debtors' ongoing expenses are expected to be satisfied by current cash, proceeds from asset sales and collections, and proceeds from litigation proceedings, and should not require the infusion of external capital. Refer to Appendix G: "Reorganized Debtors' Budget", Sections IV.E., "Avoidance Actions" and XVII., "Claims Allowance, Objection and Estimation Procedures" for further information.

a. Operating Expenses

(i) The operating expenses are made up primarily of the cost of labor resources needed to manage and liquidate the Remaining Assets, evaluate Claims, and perform other estate wind-down activities, such as the dissolution of legal entities. The wind down of the Debtors' estates remains a complicated process and will therefore require substantial resources. There are a significant number of individual assets that need to be collected or sold, or otherwise handled. Some of these assets are currently involved in litigation proceedings and/or complex cross-ownership structures. Considerable due diligence is required for the dissolution of legal entities and the resolution of Claims. The Reorganized Debtors expect to employ 1,020 employees and contractors as of the Confirmation Date. As noted in Section III.A.8.b.IV., the Debtors or the Reorganized Debtors (as may be applicable) anticipate adopting a retention incentive compensation and severance pay plan.

(ii) It is expected that the most significant operating expenses will occur in the first year and that resource requirements will diminish as assets are sold and the Reorganized Debtors achieve resolution/completion on the outstanding projects. Refer to Appendix G: "Reorganized Debtors' Budget" for a budget of the Reorganized Debtors.

b. Litigation Expenses. As discussed in more detail in Section IV.C., "Litigation and Government Investigations", the Reorganized Debtors are involved in numerous legal proceedings that will require substantial time and resources. As of the Confirmation Date, it is anticipated that the Reorganized Debtors will have significant expenses in connection with litigation. These expenses are yet to be finalized but are expected to be material in comparison to the operating expenses. Refer to Sections IV.C., "Litigation and Government Investigations" and IV.E., "Avoidance Actions" for further information.

c. Professional Fees. As of the Confirmation Date, it is expected that the Reorganized Debtors will continue to incur professional service fees until the Chapter 11 Cases are closed. These fees are related to professionals retained by the Reorganized Debtors, in the ordinary course of business, to assist in the implementation and consummation of the Plan, as well as professionals retained by the Creditors' Committee and Fee Committee; provided, however, that it is not expected that the Creditors' Committee and the Fee Committee will remain in existence until the Chapter 11 Cases are closed. Refer to Article XXX of the Plan for more information related to the respective committees. These expenses are yet to be finalized but are expected to be material in comparison to the operating expenses.

7. Allocation of Expenses

Since the Initial Petition Date, the Debtors have and will continue to allocate overhead expenses pursuant to the Overhead Allocation Formula Order up to the Confirmation Date. It is anticipated that after the Confirmation Date, the Debtors will modify the methodology in order to allocate overhead based upon post-confirmation activities. The Debtors anticipate that the primary post-confirmation activities will be (i) evaluation and resolution of claims; (ii) liquidation and disposal of Remaining Assets; and (iii) litigation and investigations. The proposed post-confirmation overhead allocation methodology will use number of claims, value of claims, and expected proceeds from asset dispositions as the primary allocation factors.

The Debtors intend to provide a detailed description of the proposed post-confirmation overhead allocation methodology to the Creditors' Committee and seek their approval of the methodology. On or before the Ballot Date, the Debtors will file a motion with the Bankruptcy Court with respect to the proposed methodology. It is expected that the Bankruptcy Court will enter an order with respect to the overhead allocation in connection with the entry of the Confirmation Order. Except as provided in such order, all other provisions of the Bankruptcy Court's orders, dated February 25, 2002, November 21, 2002 and November 25, 2002 will remain in full force and effect. Notwithstanding the foregoing or the provisions of Sections 3.1 and 3.2 of the Plan, to the extent that the Assets of a Debtor are insufficient to satisfy the administrative professional fees and the allocable overhead of such Debtor, the unsatisfied portion thereof shall be absorbed by the remaining Debtors.

VIII. Portland General Electric Company

Capitalized terms used throughout this Disclosure Statement are defined in Appendix A: "Material Defined Terms for Enron Disclosure Statement" attached hereto.

A. Business

1. General

PGE, incorporated in 1930, is a single, integrated electric utility engaged in the generation, purchase, transmission, distribution, and retail sale of electricity in the State of Oregon. PGE also sells wholesale electric energy to utilities, brokers, and power marketers located throughout the western United States. PGE's service area is located entirely within Oregon and covers 3,150 square miles. It includes 51 incorporated cities, of which Portland and Salem are the largest. PGE estimates that at the end of 2002 its service area population was approximately 1.5 million, comprising about 44% of the state's population. PGE added approximately 7,700 customers during 2002, and at December 31, 2002 served approximately 743,000 retail customers.

PGE has approximately 26,085 miles of electric transmission and distribution lines and owns 1,945 MW of generating capacity. PGE also has long-term power purchase contracts for 652 MW from four hydro-electric projects on the mid-Columbia River and power purchase contracts of one to twenty-six years for another 828 MW from BPA, other Pacific Northwest utilities, and the Tribes. At December 31, 2002, PGE's total firm resource capacity, including short-term purchase agreements, was approximately 4,434 MW (net of short-term sales agreements of 3,927 MW). The average annual demand is approximately 2,350 MW with peak demand of approximately 3,800 MW. On July 2, 1997, Portland General Corporation, the former parent of PGE, merged with ENE, with ENE continuing in existence as the surviving corporation, and PGE operating as a wholly owned subsidiary of ENE. PGE is not a Debtor in the Chapter 11 Cases.

As of December 31, 2002, PGE had 2,757 employees. This compares to 2,790 and 2,781 employees at December 31, 2001 and 2000, respectively. A total of 902 employees are covered under agreements with Local Union No. 125 of the International Brotherhood of Electrical Workers. Such agreements cover 885 employees for a two-year period effective from

March 1, 2002 through February 29, 2004; negotiations of a new agreement are expected to begin in late 2003. In addition, 17 employees at Coyote Springs are covered under an agreement effective from September 1, 2001 through August 1, 2006.

PGE is a reporting company under the Exchange Act and files annual, quarterly and periodic reports with the SEC. Refer to Section VIII.A.9., "Additional Information Filed with the SEC" for further information.

2. Operating Revenues

a. Retail. PGE's diverse retail customer base has helped mitigate the effects of a significant downturn in Oregon's economy. Residential, the largest customer class, comprises about 88% of PGE's total number of customers, and in 2002 provided 38% of total retail MWh energy sales and 41% of retail tariff revenues. Residential demand is sensitive to the effects of weather, with revenues highest during the winter heating season. Commercial and industrial customers provided about 40% and 19%, respectively, of retail tariff revenues in 2002. While total retail MWh energy sales decreased somewhat from 2001, reflecting the continuing effect of Oregon's slow economy and conservation efforts, revenues increased approximately 35%, reflecting a general rate increase that became effective October 1, 2001.

Commercial and industrial customer classes are not dominated by any single industry. While the 20 largest customers constitute about 21% of retail demand, they represent 9 different commercial and industrial groups, including paper manufacturing, high technology, metal fabrication, food merchandising, and health services. No single customer represents more than 3.4% of PGE's total retail load.

b. Wholesale Non-Trading. Non-trading wholesale electricity sales related to activities to serve retail load requirements comprised about 21% of total operating revenues in 2002, down from about 54% in 2001. The decrease was due to significantly lower wholesale market prices. Most of PGE's non-trading wholesale sales have been to utilities and power marketers and have been predominantly short-term. PGE participates in the wholesale marketplace in order to balance its supply of power to meet the needs of its retail customers, manage risk, and administer its current long-term wholesale contracts. Such participation includes power purchases and sales resulting from daily economic dispatch decisions for its own generation, which allows PGE to secure power for its customers at the lowest cost available.

c. Other Operating Revenues. Other operating revenues include net gains and losses from PGE's energy trading activities, which seek to take advantage of price movements in electricity, natural gas, and crude oil. Such activities are not reflected in PGE's retail rates. Also included are sales of natural gas in excess of generating plant requirements, and revenues from transmission services, pole contact rentals, and certain other electric services to customers.

d. Table. The following table summarizes total operating revenues and energy sales for the year ended December 31:

	2002	2001	2000
Operating Revenues (Millions)			

Residential	$567	$475	$448
Commercial(*)	550	424	388
Industrial	269	222	208
Tariff Revenues	1,386	1,121	1,044
Accrued (Collected) Revenues	82	(31)	14
Retail	1,468	1,090	1,058
Wholesale (Non-Trading)	391	1,313	774
Other Operating Revenues:			
Trading Activities-net	(1)	(11)	30
Other	(3)	28	25
Total Operating Revenues	$1,855	$2,420	$1,887
Megawatt-Hours Sold (Thousands)			
Residential	7,058	7,080	7,433
Commercial(*)	7,101	7,285	7,527
Industrial	4,612	4,675	4,912
Retail	18,771	19,040	19,872
Wholesale (Non-Trading)	12,645	9,764	12,858
Trading Activities-net	-	15	(55)
Total MWh Sold	31,416	28,819	32,675

(*) Includes public street lighting

3. Regulatory Matters

a. OPUC. PGE is subject to the jurisdiction of the OPUC, comprised of three members appointed by Oregon's governor to serve non-concurrent four-year terms. The OPUC approves PGE's retail rates and establishes conditions of utility service. The OPUC further ensures that prices are fair, equitable, and provides PGE an opportunity to earn a fair return on its investment. In addition, the OPUC regulates the issuance of stock and long-term debt, prescribes the system of accounts to be kept by Oregon utilities, and reviews applications to sell utility assets and engage in transactions with affiliated companies.

b. EFSC. Construction of new thermal generating facilities requires a permit from the EFSC.

c. FERC. PGE is also subject to the jurisdiction of FERC with regard to the transmission and sale of wholesale electric energy, licensing of hydroelectric projects, and certain other matters. PGE is a "licensee" and a "public utility" as those terms are used in the FPA and is, therefore, also subject to regulation by FERC as to accounting policies and practices, transmission and wholesale electric prices, issuance of short-term debt, and other matters.

In 1999, FERC issued Order No. 2000 requiring all owners of electricity transmission facilities to file a proposal to join a RTO or, alternatively, to file an explanation of reasons preventing them from making such filing. In response to this order, BPA and nine western utilities, including PGE, filed an initial proposal with FERC to form RTO West, a regional non-profit transmission organization that would operate the transmission system and manage pricing in the Pacific Northwest, Nevada, and small portions of California and Wyoming. In September 2002, the formation plan of RTO West received preliminary FERC approval.

Also in September 2002, FERC granted preliminary approval of a proposed rate structure for TransConnect, a new company proposed by PGE and two other regional utilities. As proposed, TransConnect would be an independent, jointly owned, for-profit transmission company that will participate in RTO West and that could own or lease the high-voltage transmission facilities currently held by PGE and its other participants.

In July 2002, FERC issued a NOPR on Standard Market Design to standardize the structure and operation of competitive wholesale markets. In April of 2003, FERC issued a White Paper setting forth its assessment of how best to move forward in the electric industry for the long-term benefit of electricity customers, and how it intends to change its proposed rule to meet concerns that have been raised. If the NOPR is implemented as proposed, it will significantly change how wholesale energy and transmission markets operate. Wholesale companies and retail load serving companies would be on a single network transmission tariff, and operational control of the transmission network would be administered by an RTO or ISO.

Decisions to move forward with the formation of RTO West and TransConnect will ultimately depend on the conditions imposed during the regulatory approval process, as well as economic considerations. Such decisions will be subject to approvals by state and federal agencies and individual company boards of directors.

d. **NRC**. The NRC regulates the licensing and decommissioning of nuclear power plants. In 1993, the NRC issued a possession-only license amendment to PGE's Trojan operating license and in early 1996 approved the Trojan Decommissioning Plan. Approval of the Trojan Decommissioning Plan by the NRC and EFSC has allowed PGE to begin decommissioning activities. In 2001, the NRC approved the LTP. The LTP outlines the process by which PGE will complete the decommissioning of the Trojan site and meet regulatory requirements for decommissioned nuclear facilities. In October 2002, the NRC approved the transfer of spent nuclear fuel from the Trojan spent fuel pool to the ISFSI, using a separately licensed dry cask storage system. Trojan is subject to NRC regulation until it is fully decommissioned, all nuclear fuel is removed from the site, decontamination is completed, and NRC licenses are terminated.

e. **PUHCA**. PGE is a subsidiary of a holding company (ENE) exempt under PUHCA, except for Section 9(a)(2) with respect to the acquisition of the securities of other public utilities. In February 2002, ENE applied to the SEC to continue its exemption, which requires that PGE's utility activities be predominantly intrastate in nature. In February 2003, the SEC Chief Administrative Law Judge issued an initial decision that denied ENE's application for exemption, holding that PGE does not meet the criteria to be predominantly intrastate in character. On February 27, 2003, ENE filed a petition for review with the SEC requesting that the SEC review the Administrative Law Judge's initial decision, reverse such initial decision, and find that ENE is entitled to exemption from PUHCA. On June 11, 2003, the SEC granted the petition, setting down a briefing schedule, which was completed on September 3, 2003. The effect of the Administrative Law Judge's initial decision denying the exemption is stayed pending the resolution of the SEC's further review. The SEC has set oral argument for December 4, 2003. In the event that the SEC denies ENE's application for exemption, ENE would be required to register as a holding company under PUHCA, and PGE would become a subsidiary of a registered holding company. As such, PGE would become subject to additional regulation by the SEC with respect to certain matters, including transactions with ENE and its subsidiaries. Refer to Section XIV.E.2., "PUHCA" for further information.

f. **Other**. The Oregon Department of Energy also monitors Trojan.

4. Competition

a. **General**. Restructuring of the electric industry has slowed both at the national level and in the Pacific Northwest. PGE continues to maintain its commitment to service excellence while accommodating the formation of a competitive electricity market in Oregon.

b. **Retail**. PGE conducts retail electric operations exclusively in Oregon within a state-approved service area. Competitors within PGE's service territory include the local natural gas company (NW Natural), which competes for the residential and commercial space and water heating market, and fuel oil suppliers that compete primarily for residential space heating customers. In addition, effective March 1, 2002, commercial and industrial customers are allowed direct access to competing electricity service suppliers in accordance with Oregon's electric power restructuring law, related regulations, and PGE's tariff. Although PGE remains obligated to serve all of its customers, under terms of a separate tariff schedule certain non-residential customers may provide PGE notice 12 months prior to the start of a calendar year that they do not want PGE to include their loads in PGE power purchases for the noticed year. Customers providing the notice may either obtain their power supply directly from an electricity service supplier or they may purchase power from PGE at then prevailing market rates (with price terms of one day to one year in length) for delivery in the noticed year. These customers are also required by the tariff to provide a year's advance notice should they choose to return to PGE for cost of service rates for a subsequent calendar year.

c. **Wholesale**. Competition has transformed the electric utility industry at the wholesale level. The Energy Policy Act, passed in 1992, opened wholesale competition to energy brokers, independent power producers, and power marketers, and provided a framework for increased competition in the electric industry. In 1996, FERC issued Order 888 requiring non-discriminatory open access transmission by all public utilities that own interstate transmission and requiring investor-owned utilities to allow others access to their transmission systems for wholesale power sales. This access must be provided at the same price and terms the utilities would apply to their own wholesale customers. It also requires reciprocity from municipals, cooperatives, and federal power marketers receiving service under the tariff and allows public utilities to recover stranded costs in accordance with the terms, conditions, and procedures set forth in the order.

PGE's transmission system connects winter-peaking utilities in the Northwest and Canada, which have access to lower variable cost hydroelectric generation, with summer-peaking wholesale customers in California and the Southwest, which have higher variable cost fossil fuel generation. PGE uses portions of this system to purchase and sell in both markets depending upon the relative price and availability of power, water conditions, and seasonal demand from each market.

The amount of surplus electric generating capability in the western United States, the amount of annual snow pack and its impact on hydro generation, the number and credit quality of wholesale marketers and brokers participating in the energy trading markets, the availability and price of natural gas as well as other fuels, and the availability and pricing of electric and gas transmission all contributed to and have an impact on the wholesale price and availability of electricity. PGE will continue its participation in the wholesale energy marketplace in order to manage its power supply risks and acquire the necessary electricity and fuel to meet the needs of its retail customers and administer its current long-term wholesale contracts. In addition, PGE will continue its trading activities to take advantage of price movements in electricity, natural gas, and crude oil.

d. Public Ownership Initiatives. There is the potential for the loss of service territory and assets from the creation of PUDs or municipal utilities in PGE's service territory. Initiative petitions circulated in Multnomah County obtained sufficient signatures to place a measure on an election ballot that, if passed, could result in the formation of a PUD in Multnomah County. In June 2003, the Multnomah County Board of Commissioners determined the boundaries of a proposed PUD and set a PUD formation initiative on the November 4, 2003 ballot to be voted on by the county voters. The initiative failed. In August 2003, initiative petitions circulated in Yamhill County also obtained sufficient signatures to place a measure on an election ballot. The Yamhill County Commissioners determined the boundaries of the proposed PUD and set March 2, 2004 as the date for voting on the formation initiative. The expressed intent of the PUD supporters is to have additional elections to expand the PUD boundaries to include all of PGE's service territory. If a PUD were formed, it would have the authority to condemn PGE's distribution assets within the boundaries of the district provided that it paid fair value for such assets. Oregon law prohibits a PUD from condemning thermal generation plants. It is uncertain under Oregon law whether a PUD would be able to condemn PGE's hydro generation plants. Refer to Section XIV.G.1.b., "Condemnation" for further information.

5. Power Supply

a. General. To meet its customers' energy needs, PGE relies upon its existing base of generating resources, long-term power contracts, and short-term purchases that together provide flexibility to respond to consumption changes and Oregon's electric power restructuring law. Short-term purchases include both spot and firm purchases for periods of less than one year in duration.

PGE has filed with the OPUC a new Integrated Resource Plan describing its strategy to meet the electric energy needs of its customers. The Integrated Resource Plan, which considers resource actions over the next two to three years, includes reduced reliance on short-term wholesale power contracts and increased emphasis on longer-term supplies. It also considers future investment in existing and new generating resources, an increase in renewable resources, long-term power purchases, and meeting seasonal peaking requirements through seasonal exchanges, demand-side management, capacity tolling contracts, and combustion turbine development. PGE has issued a RFP to acquire energy and capacity resources. PGE has received responses from more than 40 entities with more than 90 proposals involving energy solutions ranging from wind and geothermal resources to coal and natural gas resources. PGE intends to identify specific parties and initiate negotiations and, based upon the results, update its resource action plan with specific recommendations. PGE has also issued a request for qualifications to approximately 150 of its largest business customers, seeking interest in voluntary demand management programs. Such programs generally consist of an agreement between PGE and the customer to either reduce or adjust the timing of electricity consumption during periods of peak usage or critical power shortage in order to encourage efficient use of resources, thereby enabling PGE to minimize resource costs. PGE intends to identify qualifying proposals and include them in PGE's resource action plan. Based upon results of the RFP, PGE will update its action plan with specific resource recommendations and request acknowledgement that PGE's final action plan is consistent with least cost planning principles established by the OPUC. There can be no assurances, however, that PGE will receive the OPUC acknowledgement.

b. Hydro Conditions. Northwest hydro conditions have a significant impact on the region's power supply, with water conditions significantly impacting PGE's cost of power and its ability to economically displace more expensive thermal generation and spot market power purchases. In the last half of 2000 and first half of 2001, both the cost and availability of power were adversely affected by a reduction in the availability of surplus generation and weather conditions in California and the Southwest that resulted in high demand. In addition, higher natural gas prices and very poor Northwest hydro conditions (accentuated by fish protection spill requirements) further resulted in increased costs and reduced supply. From mid-2001 through the first quarter of 2003, however, additional generation from both new plants and from those returning to service, moderating weather conditions, additional natural gas supplies, federal price mitigation, and a reduction in demand from both a significant downturn in Oregon's economy and conservation efforts have resulted in significantly lower market prices for electricity. These events have affected the balance of market supply and demand, and several independent power producers have delayed or cancelled plans for new generating plants.

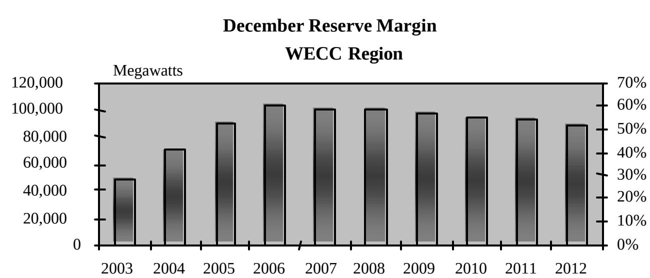
c. Generating Capability. PGE's existing hydroelectric, coal-fired, and gas-fired plants are important resources for PGE, providing 1,945 MW of generating capability. PGE's lowest-cost producers are its five FERC-licensed hydroelectric projects incorporating eight powerhouses on the Clackamas, Sandy, Deschutes, and Willamette rivers in Oregon. These facilities operate under federal licenses, which will be up for renewal through 2006. Based on a comparison of projected future operating costs to the projected future value of its energy output, PGE has decided not to relicense its Bull Run hydroelectric project.

In early 2001, PGE filed a "Notice of Intent" with Oregon's EFSC to build the Port Westward Generating Project, a new 650-MW gas turbine plant adjacent to the Beaver plant site. An air contamination discharge permit application has been approved, with a site certificate issued on November 8, 2002. All other required permits have either been obtained or are anticipated before year end 2003. PGE has not made a decision whether to develop this project at this time. Further decisions regarding the Port Westward project are subject to OPUC acknowledgement of PGE's Integrated Resource Plan and the results of the RFP process.

d. Purchased Power. PGE supplements its own generation with long-term and short-term contracts as needed to meet its retail load requirements.

(i) Long-Term. PGE has long-term power contracts with four hydroelectric projects on the mid-Columbia River, which provide approximately 652 MW of firm capacity. PGE also has firm contracts, ranging from one to twenty-six years, to purchase 828 MW of power from BPA, other Pacific Northwest utilities, and the Tribes. In addition, PGE has an exchange contract with a summer-peaking Southwest utility to help meet PGE's winter-peaking requirements, and an exchange contract with a Northwest utility to help meet PGE's summer-peaking requirements. These resources, along with short-term contracts, provide PGE with sufficient firm capacity to serve its peak loads.

(ii) Short-Term. PGE relies on wholesale market purchases within the WECC in conjunction with its base of generating resources to supply its resource needs, including short-term purchases, and maintain system reliability. The WECC is the largest and most diverse of the 10 regional electric reliability councils. It provides coordination for operating and planning a reliable and adequate electric power system for the western continental United States, Canada, and Mexico. It further supports competitive power markets, helps assure open and non-discriminatory transmission access among members, provides a forum for resolving transmission access disputes, and provides an environment for coordinating the operating and planning activities of its 145 members. The WECC area, which extends from Canada to Mexico and includes 14 western states, has great diversity in climate and peak loads that occur at different times of the year. Energy loads in the Southwest peak in the summer due to air conditioning use, while northern loads peak during winter heating months. According to WECC forecasts, its members, which serve about 71 million people, will have sufficient capacity margin to meet forecast demand and energy requirements through the year 2012, assuming the timely completion of planned new generation.



PGE's peak load in 2002 was 3,408 MW. Approximately 43% of PGE's 2002 peak load was met with short-term purchases. At December 31, 2002, PGE's total firm resource capacity, including short-term purchase agreements, was approximately 4,434 MW (net of short-term sales agreements of 3,927 MW).

6. Fuel Supply

Fuel supply contracts are negotiated to support annual planned plant operations. Flexibility in contract terms allows for the most economic dispatch of PGE's thermal resources in conjunction with the current market price of wholesale power.

a. Coal

(i) Boardman. PGE negotiates agreements each year to purchase coal for Boardman in the following calendar year, and currently has agreements that cover the plant's requirements through 2003. Available coal supplies are sufficient to meet future requirements of the plant. The coal, obtained from surface mining operations in Wyoming and Montana and subject to federal, state, and local regulations, is delivered by rail under contracts with the Burlington Northern Santa Fe and Union Pacific Railroads. Coal purchases in 2002, totaling about 2.1 million tons, contained approximately 0.4% of sulfur by weight. Utilizing electrostatic precipitators, the plant emitted less than the EPA-allowed limit of 1.2 pounds of sulfur dioxide per MMBtu.

(ii) Colstrip. Coal for Colstrip Units 3 and 4, located in southeastern Montana, is provided under contract with Western Energy Company, a wholly owned subsidiary of Westmoreland Mining LLC. The contract provides for delivered coal to not exceed a maximum sulfur content of 1.5% by weight. Utilizing wet scrubbers to minimize sulfur dioxide emissions, the plant operated in compliance with EPA's source-performance standards.

b. Natural Gas. PGE utilizes long-term, short-term, and spot market purchases to secure transportation capacity and gas supplies sufficient to fuel plant operations. PGE re-markets natural gas and transportation capacity in excess of its needs.

(i) Beaver. PGE owns 79% of the Kelso-Beaver Pipeline, which directly connects its Beaver generating station to Northwest Pipeline, an interstate gas pipeline operating between New Mexico and British Columbia, Canada. Firm gas supplies for Beaver, based on anticipated operation of the plant, are purchased at fixed prices for up to 24 months in advance. PGE has access to 76,000 Dth/day of firm transportation capacity, sufficient to operate Beaver at a 70% load factor. In addition, PGE has contractual access, through October 2004, to natural gas storage in Mist, Oregon, from which it can draw natural gas in the event the plant's supply is interrupted or if economic factors indicate its use. PGE believes that sufficient market supplies of gas are available to fully meet requirements of the plant in 2003 and beyond.

(ii) Coyote Springs. Coyote Springs utilizes 41,000 Dth/day of firm transportation capacity on three interconnecting pipeline systems accessing gas fields in Alberta, Canada. Firm gas supplies for Coyote Springs, based on anticipated operation of the plant, are purchased at fixed prices for up to 24 months in advance. PGE believes that sufficient market supplies of gas are available to fully meet requirements of the plant in 2003 and beyond.

c. Oil

(i) Beaver. Beaver has the capability to operate at full capacity on No. 2 diesel fuel oil when it is economical to do so or if the plant's natural gas supply is interrupted. To ensure the plant's continued operability under such circumstances, PGE had an approximate 19-day supply of oil at the plant site at December 31, 2002.

(ii) Coyote Springs. Coyote Springs has the capability to operate on oil if needed, with sufficient fuel maintained on-site to run the plant for 40-50 hours.

7. Environmental Matters

PGE operates in a state recognized for environmental leadership. PGE's policy of environmental stewardship emphasizes minimizing both waste and environmental risk in its operations, along with promoting the wise use of energy.

a. Regulation. PGE's operations are subject to a wide range of environmental protection laws covering air and water quality, noise, waste disposal, and other environmental issues. The EPA regulates the proper use, transportation, cleanup, and disposal of PCBs. The NRC regulates the storage and disposal of spent nuclear fuel from the Trojan plant. State agencies or departments, which have direct jurisdiction over environmental matters, include the Environmental Quality Commission, the DEQ, the Oregon Office of Energy, and the EFSC. Environmental matters regulated by these agencies include the siting and operation of generating facilities and the accumulation, cleanup, and disposal of toxic and hazardous wastes.

b. Threatened and Endangered Species. Populations of many salmon species in the Pacific Northwest have shown significant decline over the last several decades. The listing of various species of fish, wildlife, and plants as threatened or endangered species has given rise to potentially significant changes to hydroelectric project operations, the impacts of which to date have been minimal. The biggest change has been modifying the timing of releases of water stored behind the dams in the upper part of the Columbia and Snake River basins.

PGE continues to evaluate the impact of current and potential ESA listings on the operation of its hydroelectric projects on the Deschutes, Sandy, Clackamas, and Willamette rivers. PGE's hydroelectric relicensing efforts, in combination with endangered species consultations among FERC, NMFS, and the USFWS, address issues associated with the protection of fish runs on those rivers where PGE operates hydroelectric facilities. The agencies have completed an ESA consultation on the Deschutes River, the location of PGE's Pelton Round Butte Project, that will be in effect until a new license is granted by FERC; no significant operational changes to the project have been indicated. PGE awaits conclusion by the federal agencies of consultation with respect to its hydroelectric project on the Sandy River. PGE currently is supporting the federal agencies' ESA consultation activities regarding PGE's projects on the Clackamas and Willamette rivers, with minor operational changes implemented in February 2003 on the Clackamas and planned for 2004 on the Willamette.

c. Air Quality. PGE's operations, principally its fossil-fuel electric generation plants, are subject to the federal CAA and other federal regulatory requirements. State governments are also charged with monitoring and administering certain portions of the Act and are required to set guidelines that are at least equal to federal standards; Oregon's air quality standards exceed federal standards. Primary pollutants addressed by the CAA that affect

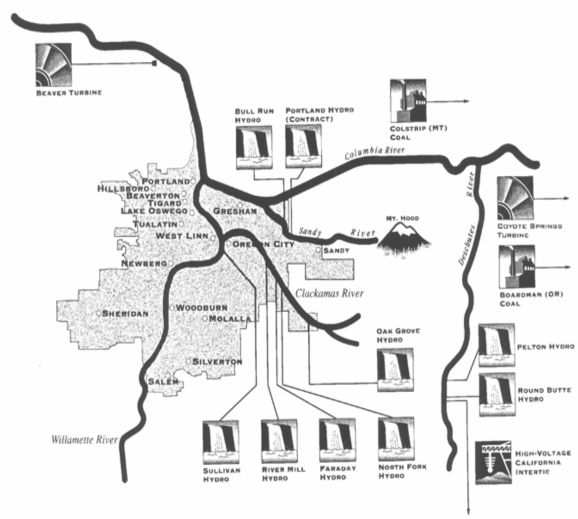
PGE are SO2, NOx, CO, and particulate matter. PGE manages its emissions by the use of low sulfur fuel, emission controls, emission monitoring, and combustion controls.

The SO2 emission allowances awarded under the CAA, along with expected future annual allowances, are sufficient to operate Boardman at a 60% to 67% capacity without emissions reductions. In addition, current emission allowances are sufficient to operate Colstrip, which utilizes wet scrubbers. If necessary, PGE intends to acquire sufficient additional allowances in order to meet excess capacity needs. It is not yet known what impacts federal regulations on mercury transport, regional haze, or particulate matter standards may have on future plant operations, operating costs, or generating capacity.

Federal operating air permits, issued by DEQ, have been obtained for all of PGE's thermal generating facilities.

d. Superfund. A 1997 investigation of a portion of the Willamette River known as the Portland Harbor, conducted by the EPA, revealed significant contamination of sediments within the harbor. Subsequently, the EPA has included Portland Harbor on the federal National Priority list pursuant to CERCLA. In December 2000, PGE, along with 68 other companies on the Portland Harbor Initial General Notice List, received a "Notice of Potential Liability" with respect to the Portland Harbor superfund site. Available information is currently not sufficient to determine either the total cost of investigation and remediation of the Portland Harbor or the potential liability of responsible companies, including PGE. It is believed that PGE's contribution to the sediment contamination, if any, would qualify it as a de minimis potentially responsible party under CERCLA. Refer to Section XIV.G.3.a., "Portland Harbor" for further information about the risks associated with the Portland Harbor superfund site.

8. Properties



PGE's principal plants and appurtenant generating facilities and storage reservoirs are situated on land owned by PGE in fee or land under the control of PGE pursuant to existing leases, federal or state licenses, easements, or other agreements. In some cases, meters and transformers are located on customer property. The indenture securing PGE's First Mortgage Bonds constitutes a direct first mortgage lien on substantially all utility property and franchises, other than expressly excepted property. PGE's service territory and generating facilities are indicated on the map above.

The following are generating facilities owned by PGE:

Facility	**Location**	**Fuel**	**Net MW Capability At Dec. 31, 2002(*)**
<u>Wholly Owned:</u>			
Faraday	Clackamas River	Hydro	48
North Fork	Clackamas River	Hydro	58
Oak Grove	Clackamas River	Hydro	44
River Mill	Clackamas River	Hydro	25

Facility	Location	Fuel	Net MW Capability At Dec. 31, 2002(*)	
Bull Run	Sandy River	Hydro	22	
Sullivan	Willamette River	Hydro	16	
Beaver	Clatskanie, OR	Gas/Oil	529	
Coyote Springs	Boardman, OR	Gas/Oil	245	
Jointly Owned:				PGE Interest
Boardman	Boardman, OR	Coal	362	65.00%
Colstrip 3 & 4	Colstrip, MT	Coal	296	20.00%
Pelton	Deschutes River	Hydro	73	66.67%
Round Butte	Deschutes River	Hydro	227	66.67%
Total			1,945	

(*) PGE ownership share.

PGE holds licenses under the FPA for its hydroelectric generating plants, as well as licenses from the State of Oregon for all or portions of five of the plants. Licenses for the Sullivan and Bull Run projects expire in 2004 and licenses for all projects on the Clackamas River expire in 2006. The license for the Pelton Round Butte project expired at the end of 2001. In June 2001, PGE and the Tribes jointly filed a 50-year license application for the Pelton Round Butte project, which is pending with FERC.

FERC requires that a notice of intent to relicense hydroelectric projects be filed approximately five years prior to license expiration. PGE has filed notice to relicense and is actively pursuing renewal of licenses for all of its hydroelectric generating plants except Bull Run, which will not be relicensed. PGE has determined not to relicense Bull Run based upon a comparison of projected future operating costs, including measures to protect endangered salmon, with the future value of its energy output.

On January 1, 2002, PGE sold a 33.33% undivided interest in its Pelton Round Butte hydroelectric project to the Tribes.

The rated generating capability at Beaver increased 5 MW based upon revised measurements of the plant's performance in 2002. The generating capability at Faraday increased 4 MW in 2002 due to turbine replacement and rehabilitation.

PGE owns transmission lines that deliver electricity from its Oregon plants to its distribution system in its service territory and also to the Northwest grid. PGE also has ownership in, and contractual access to, transmission lines that deliver electricity from the Colstrip plant in Montana to PGE. In addition, PGE owns approximately 16% of the Pacific Northwest Intertie, a 4,800-MW transmission facility between John Day, in northern Oregon, and Malin, in southern Oregon near the California border. This line is used primarily for interstate purchases and sales of electricity among utilities, including PGE.

PGE leases its headquarters complex in Portland, Oregon under a 40-year sale-lease back arrangement, ending in September 2018. The lease payments are a fixed amount for the initial term. The lease may be renewed at a predetermined fixed amount for two 10-year and one five-year renewal terms. PGE also leases the coal handling facilities at the Boardman plant under a 27-year leveraged lease financing expiring January 2005. The lease has fixed payments for the initial term and may be renewed for an initial renewal of 5 years at a fixed rent, and thereafter for any length of time at a fair market value, provided the total of all renewal terms may not exceed 20 years.

9. Additional Information Filed with the SEC

The Debtors refer to the following reports filed with the SEC by PGE.

- PGE's Annual Report on Form 10-K for the fiscal year ended December 31, 2002;

- PGE's Quarterly Reports on Form 10-Q for the quarters ended March 31, 2003, June 30, 2003 and September 30, 2003; and

- PGE's Current Reports on Form 8-K dated March 25, April 8, April 29, May 21, June 4, June 25, June 27, August 4, September 18 and September 26, 2003.

These reports contain information about PGE including, without limitation, information related to the following matters:

- Legal Proceedings;

- Management's Discussion and Analysis of Financial Condition and Results of Operations;

- Hedging and Market Risk;

- Directors and Executive Officers;

- Executive Compensation; and

- Certain Relationships and Related Transactions.

The Debtors did not prepare such reports, but they are publicly available as information that may be relevant to the Creditors' decision in voting on the Plan.

10. Other Information Regarding PGE Contained in This Disclosure Statement

Refer to Section XIV.G., "PGE Risks" for further information about certain risks associated with PGE. Refer to Section IV.C., "Litigation and Government Investigations" for further information about certain legal proceedings involving PGE.

11. Separation of PGE From ENE

The Plan contemplates that the Existing PGE Common Stock held by ENE may be cancelled and the PGE Common Stock may be issued and distributed to the creditors of the Debtors, or to an Operating Trust, in accordance with the terms of the Plan. Upon such issuance, the preferred stock of PGE described in Section VIII.D., "Capital Stock" will remain outstanding. In connection with the consummation of the Plan, PGE and ENE expect to agree to certain separation agreements that would govern the relationship between ENE and PGE on a transitional basis, including the provision of various corporate and administrative services. The existing relationship between ENE and PGE is governed by the PGE MSA and a tax sharing agreement. Refer to Sections VII.B.1.a(ii), "Auxiliary Agreements" and VII.B.1.a(iii), "Tax Sharing Agreement" for further information about these agreements.

The issuance and distribution of the PGE Common Stock in accordance with the terms of the Plan will require various governmental approvals, including approvals from the OPUC, FERC, the NRC and the FCC. In addition, as described in Section XIV.E.2., "PUHCA", there is a proceeding pending at the SEC that could result in the loss of ENE's exempt status and require ENE to register as a holding company under PUHCA. If ENE is a registered holding company at the time of the distribution, SEC authorization may be required in order to effect the distribution of the PGE Common Stock. As a result of PGE's ownership and operation of its Coyote Springs generation facility, PGE also may need to obtain approval from Oregon's EFSC for the distribution, or a determination by the EFSC that the distribution does not cause a "transfer of ownership" of such generation facility. Although the Debtors believe that all required approvals will be obtained, the ability to complete the distribution of the PGE Common Stock to the creditors of the Debtors or to an Operating Trust, in accordance with the terms of the Plan, will depend upon successfully obtaining the required approvals.

12. Potential Sale of PGE

Notwithstanding the foregoing, ENE is continuing its previously announced sales process with respect to its interest in PGE and reserves the right, at any time prior to the satisfaction of the conditions for a distribution of the PGE Common Stock to the Creditors under the Plan, as described in Section I., "Overview of Chapter 11 Plan" to enter into an agreement to sell such interest. If PGE is sold, ENE's proceeds of such sale (rather than the capital stock of PGE held by ENE) will be distributed to the creditors of the Debtors in accordance with the terms of the Plan. The Plan provides for PGE Common Stock to be distributed to Creditors in accordance with the Plan or the sale of PGE as a going concern. A break-up of PGE is not an option under the Plan.

B. Historical Financials, Projections and Valuation

1. Historical Financials

The following selected unaudited consolidated financial information for each of the three years in the period ended December 31, 2002 has been derived from the audited consolidated financial statements of PGE for the respective periods. The Unaudited Selected Financial Information should be read in conjunction with the PGE Annual Report on Form 10-K for the year ended December 31, 2002.

	FOR THE YEARS ENDED DECEMBER 31,		
	2002	**2001**	**2000**
	(In Millions, except ratios)		
Operating Revenues [a]	$1,855	$2,420	$1,887
Net Operating Income	135	134	206
Net Income	66	34	141
Total Assets	3,250	3,474	3,452
Long Term Obligations [b]	1,046	972	880
Other Financial Data:			
Ratio of earnings to fixed charges	2.40x	1.41x	3.63x

(a) Amounts for 2000 and 2001 have been reclassified from those previously reported, in accordance with requirements of EITF 02-3, Accounting for Contracts Involved in Energy Trading and Risk Management Activities. For further information, refer to Note 1, Summary of Significant Accounting Policies, in the Notes to the Company's financial statements in the Form 10-K.

(b) Includes long-term debt and preferred stock subject to mandatory redemption requirements

2. Projections

In conjunction with formulating the Plan, as set forth on Appendix H: "PGE Financial Projections – 2003-2006", financial projections have been prepared for PGE for the four years ending December 31, 2006. The projections for the fiscal year ended December 31, 2003, include actual results through June 30, 2003. The projections are based on a number of assumptions made with respect to the future operations and performance of PGE and should be reviewed in conjunction with a review of the principal assumptions set forth on Appendix H: "PGE Financial Projections – 2003-2006". While the projections were prepared in good faith and the Debtors believe the assumptions, when considered on an overall basis, to be reasonable in light of the current circumstances, it is important to note that the Debtors can provide no assurance that such assumptions will be realized and Creditors must make their own determinations as to the reasonableness of such assumptions and the reliability of the projections. Refer to Section XIV., "Risk Factors and Other Factors to be Considered" for a discussion of numerous risk factors that could affect PGE's financial results.

3. Valuation

Also in conjunction with formulating the Plan, the Debtors determined that it was necessary to estimate the post-confirmation going concern enterprise value and equity value of PGE. Accordingly, Blackstone and the Debtors formulated such a valuation, which is utilized in the Blackstone Model. Such valuation is based, in part, on the financial projections prepared by PGE management and included in Appendix H: "PGE Financial Projections – 2003-2006". The valuation analysis was used, in part, for the purpose of determining the value of PGE to be distributed to Creditors pursuant to the Plan and to analyze the relative recoveries to Creditors under the Plan.

a. Estimated Value. Based upon the methodology described below, the Blackstone Model utilizes an estimated equity value of $1.278 billion for PGE at June 30, 2003. Therefore, assuming 62.5 million shares of new PGE Common Stock will be issued and distributed to or on behalf of Creditors pursuant to the Plan, the value of such stock is estimated to be $20.45 per share; provided, however, that such estimate does not reflect any dilution resulting from any long-term equity incentive compensation plan(s) as may be adopted by PGE. However, it is anticipated that the impact of any such plan(s) to be adopted by PGE, CrossCountry and Prisma will, in the aggregate, represent less than 1% of the overall value to be distributed under the Plan. The estimated value is based upon a variety of assumptions, as referenced below under "Variances and Risks," deemed appropriate under the circumstances. In addition, the valuation of CrossCountry does not include the anticipated costs associated with the voluntary termination of the ENE Cash Balance Plan. The estimated value per share of the new PGE Common Stock may not be indicative of the price at which the new PGE Common Stock will trade when and if a market for the new PGE Common Stock develops, which price could be lower or higher than the estimated value of the new PGE Common Stock. Accordingly, there can be no assurance that the new PGE Common Stock will subsequently be purchased or sold at prices comparable to the estimated values set forth above. Refer to Section XIV., "Risk Factors and Other Factors to be Considered" for a discussion of numerous risk factors that could affect PGE's financial results.

b. Methodology. Three methodologies were used to derive the value of PGE based on the financial projections attached as Appendix H: "PGE Financial Projections – 2003-2006": (i) a comparison of PGE and its projected performance to the comparable companies and how the market values them (ii) a comparison of PGE and its projected performance to comparable companies in precedent transactions, and (iii) a calculation of the present value of the free cash flows under the PGE projections, including an assumption for the value of PGE at the end of the projected period.

The market-based approach involves identifying (i) a group of publicly traded companies whose business as a whole, or significant portions thereof, are comparable to those of PGE, and (ii) comparable precedent transactions involving the acquisition of comparable companies, and then calculating ratios of various financial results or statistics to the public market values of these companies, or the net proceeds of these transactions. The ranges of ratios derived are applied to PGE's historical results and projected performance, and adjusted for net debt to arrive at a range of implied values. The discounted cash flow approach involves deriving the unlevered free cash flows that PGE would generate assuming the PGE projections were realized. These cash flows, and an estimated value of PGE at the end of the projected period, are discounted to the present at PGE's estimated weighted average cost of capital to determine PGE's enterprise value. Net debt is then deducted to determine the equity value.

4. Variances and Risks. Refer to Section XIV.C., "Variance from Valuations, Estimates and Projections" for a discussion regarding the potential for variance from the projections and valuation described above and Section XIV., "Risk Factors and Other Factors to be Considered" in general for a discussion of risks associated with PGE.

ESTIMATES OF VALUE DO NOT PURPORT TO BE APPRAISALS NOR DO THEY NECESSARILY REFLECT THE VALUES WHICH MAY BE REALIZED IF ASSETS ARE SOLD. THE ESTIMATES OF VALUE REPRESENT HYPOTHETICAL EQUITY VALUES ASSUMING THE IMPLEMENTATION OF PGE'S BUSINESS PLAN AS WELL AS OTHER SIGNIFICANT ASSUMPTIONS. SUCH ESTIMATES WERE DEVELOPED

SOLELY FOR PURPOSES OF FORMULATING AND NEGOTIATING A CHAPTER 11 PLAN FOR THE DEBTORS AND ANALYZING THE PROJECTED RECOVERIES THEREUNDER. THE ESTIMATED EQUITY VALUE IS HIGHLY DEPENDENT UPON ACHIEVING THE FUTURE FINANCIAL RESULTS SET FORTH IN THE PROJECTIONS AS WELL AS THE REALIZATION OF CERTAIN OTHER ASSUMPTIONS WHICH ARE NOT GUARANTEED.

THE VALUATIONS SET FORTH HEREIN REPRESENT ESTIMATED VALUES AND DO NOT NECESSARILY REFLECT VALUES THAT COULD BE ATTAINABLE IN PUBLIC OR PRIVATE MARKETS. THE EQUITY VALUE ASCRIBED IN THE ANALYSIS DOES NOT PURPORT TO BE AN ESTIMATE OF THE MARKET VALUE OF PGE STOCK DISTRIBUTED PURSUANT TO A CHAPTER 11 PLAN. SUCH TRADING VALUE, IF ANY, MAY BE MATERIALLY DIFFERENT FROM THE EQUITY VALUE ASSOCIATED WITH THE VALUATION ANALYSIS.

PGE OPERATES IN A HEAVILY GOVERNMENT REGULATED INDUSTRY. CHANGES TO THE CURRENT REGULATORY ENVIRONMENT MAY HAVE A MATERIAL ADVERSE IMPACT ON PGE'S ACTUAL RESULTS. REFER TO THE ENTIRETY OF SECTION VIII., "PORTLAND GENERAL ELECTRIC COMPANY" AND SECTION XIV., "RISK FACTORS AND OTHER FACTORS TO BE CONSIDERED" FOR FURTHER DISCUSSION ON THESE AND OTHER RISKS ATTENDANT WITH PGE AND THE ELECTRIC UTILITY INDUSTRY.

C. Legal Proceedings

Certain of PGE and its subsidiaries are currently involved either as plaintiffs or defendants in pending arbitrations or civil litigation. Those matters that may be material to PGE's business are identified below. In addition, certain of PGE and its subsidiaries are involved in regulatory or administrative proceedings. Refer to Section IV.C, "Litigation and Government Investigations" for further information.

1. Utility Reform Project, Colleen O'Neil and Lloyd K. Marbet v. Oregon Public Utilities Commission and Portland General Electric Company. (No. SC S45653, Supreme Court, State of Oregon; No. 94C-10417, Marion County Circuit Court No. 94C-10417; OPUC UM989). The OPUC approved recovery of $250 million of PGE's investment in Trojan and a return on the investment. Recovery was occurring by amortization through 2011 plus a return on the unamortized balance through that date. Numerous challenges, appeals and requested reviews were filed in Marion County, Oregon Circuit Court, the Oregon Court of Appeals, and the Oregon Supreme Court on the issue of the OPUC's authority under Oregon law to grant recovery of and a return on the Trojan investment. The primary plaintiffs in the litigation were the CUB and the URP. In June 1998, the Oregon Court of Appeals ruled that the OPUC properly granted PGE recovery of its investment in Trojan, but not a return on the investment during the amortization period and remanded the case to the OPUC. PGE's petition for review to the Oregon Supreme Court was granted in April 1999 as was the URP petition for review. While the petitions for review of the 1998 Oregon Court of Appeals decision were pending at the Oregon Supreme Court, PGE, CUB, and the staff of the OPUC entered into agreements to settle the litigation. The URP challenged the settlement at the OPUC. The settlement agreement was finally approved by the OPUC in March 2002. The URP has appealed the OPUC decision on the settlement to the Marion County, Oregon Circuit Court. On November 19, 2002 the Oregon Supreme Court dismissed the petitions for review of the 1998 Court of Appeals decision filed by PGE and the URP. As a result, the 1998 Oregon Court of Appeals opinion stands and the matter was remanded to the OPUC. On November 7, 2003, the Marion County, Oregon Circuit Court issued an opinion remanding the case to the OPUC for action to reduce rates or order refunds. PGE intends to appeal.

2. Portland General Electric v. International Brotherhood of Electrical Workers, Local No. 125. (No. 0205-05132, Circuit Court, Multnomah County, Oregon). PGE filed declaratory relief against the International Brotherhood of Electrical Workers Local 125 ("IBEW") seeking a declaratory ruling that the four grievances filed by the union seeking recovery of 401(k) plan losses under the collective bargaining agreement are not subject to arbitration. On August 14, 2003, the judge granted PGE's motion for summary judgment finding those grievances are not subject to arbitration. The IBEW has appealed the decision.

3. Portland General Electric, et al. v. The United States of America, et al. (No. C.A. 1:00-1425, Southern District of New York, C.A. No. 1:98-2552, District of Columbia, "Case No. 1425"). This is an action by PGE and other Trojan owners to recover approximately $16 million from the USDOE for assessments not authorized by fixed price contracts for enrichment of nuclear fuel. A companion case filed in the U.S. Court of Claims has been dismissed.

4. Department of Water Resources v. ACN Energy, et al., including PGE, Enron Power Corp., PG&E Energy Services nka Enron Energy Marketing Corp. and Enron North America, Inc. (No. 01 AS05497, Superior Court, Sacramento County, California). The State of California is seeking declaratory relief to resolve all claims related to the governor's seizure of the block forward contracts for energy delivery in January and February 2001. PGE filed a claim in May 2001 with the California Victims Compensation Board to preserve its right to collect approximately $70 million for energy sales to California. The State refused to toll the statute of limitations on PGE's right to appeal the denial of its claim by the Victims Compensation Board; therefore PGE filed a new lawsuit against the State restating its claim. This suit has been consolidated with the prior suit.

5. Dreyer, Gearhart and Kafoury Bros., LLC v. Portland General Electric Company (No. 03C 10639, Circuit Court, Marion County, Oregon) and Morgan v. Portland General Electric Company (No. 03C 10639, Circuit Court, Marion County, Oregon (Identical cases have also been filed in the Circuit Court of Multnomah County Oregon). On January 17, 2003, two class actions suits were filed against PGE on behalf of two classes of electric service customers. The *Dreyer* case seeks to represent current PGE customers that were customers during the period from April 1, 1995 to October 1, 2001, and the *Morgan* case seeks to represent PGE customers that were customers during the period from April 1, 1995 to October 1, 2001, but who are no longer customers. The suits seek damages of $190 million for the *Dreyer* Class and $70 million for the *Morgan* Class, from the inclusion of a return on investment of Trojan in the rates PGE charges its customers. PGE has filed motions to dismiss both suits in both Circuit Courts. The plaintiffs have withdrawn the Multnomah County suit.

6. Gordon v. Reliant Energy, Inc., Duke Energy Trading & Marketing, et al. v. Arizona Public Service Company, et al. (In re: Wholesale Electricity Antitrust Cases I & II) (No. 02—990,1000, 1001, United States District Court, Southern District of California; No. 02-57200, United States Court of Appeals, Ninth Circuit). In late 2001, numerous individuals, businesses, California cities, counties and other governmental agencies filed class action lawsuits in California state court against various individuals, utilities, generators, traders, and other entities alleging that activities related to the purchase and sale of electricity in California in 2000-2001 violated California anti-trust and unfair competition law. The complaint seeks restitution of all funds acquired by means that violate the law, payment of treble damages and interest and penalties. In late April 2002, the defendant parties filed a cross-complaint against PGE and other utilities, generators, traders, and other entities not named in the cases, alleging that they participated in the purchase and sale of electricity in California during 2000-2001 and seeking a complete indemnification and/or partial equitable indemnity on a comparative fault basis for any liability that the court may impose on the defendant parties. No specific dollar amount is claimed. The cases were removed to federal court on December 13, 2002. The federal court granted the plaintiffs' motions to remand to state court and to strike and/or sever cross-complaints. The defendant parties appealed the remand to the Ninth Circuit Court of Appeals. The Court of Appeals issued orders stating it had jurisdiction to hear the appeal of the remand order and staying the remand order pending its decision. The parties have agreed to an open extension of time until 30 days after a ruling on jurisdiction is made.

7. People of the State of California, ex rel. Bill Lockyer, Attorney General v. Portland General Electric Company (No. C-02-3318, United States District Court, Northern District of California). The Attorney General of California filed a complaint alleging that PGE failed to comply with FERC's approval requirements for its market-based sales of power in California. The complaint does not specify damages; however it seeks fines and penalties under the California Business and Professions Code for each sale from 1998 through 2001 above a capped price. In July 2002, PGE removed the case to federal district court and filed a motion to dismiss on preemption grounds. The Attorney General filed a motion with the district court to remand the case to state court. The motion was denied and the Attorney General appealed the denial to the Ninth Circuit and filed a motion to stay the district court. The district court found the appeal frivolous and on March 25, 2003 granted the motion to dismiss on preemption grounds. The Attorney General filed an appeal of the dismissal to the Ninth Circuit. On September 26, 2003, PGE and the California Attorney General, as part of PGE's settlement with the Staff of FERC and others related to certain investigations and cases related to electricity prices in California in 2000-2001, entered into a settlement agreement that resolves this case, along with related non-public investigations by the California Attorney General. The settlement has been submitted to FERC for approval. Refer to Section VIII.C.14., "FERC Investigation of Trading Activities" for further information.

8. Cyber-Tech, Inc. v. PGE et al. (No. 0305-05257, Circuit Court, Multnomah County, Oregon). Cyber-Tech, in the business of designing and supplying industrial control handles and joysticks for commercial and personal use, seeks recovery of approximately $4.3 million for property damage and lost profits resulting from a disruption of power to its facility when PGE's contractor, Henkles & McCoy, allegedly damaged PGE's underground electrical equipment, which in turn caused the disruption of power. Another PGE contractor, Locating

Inc., is alleged to have improperly located the underground facilities. Tenders of defense on behalf of PGE have been sent to both Henkles & McCoy and Locating, Inc.

9. Port of Seattle v. Avista et al., including PGE (No. 03-1170, United States District Court, Western District of Washington, Seattle Division). On May 21, 2003, the Port of Seattle, Washington filed a complaint against PGE and sixteen other companies alleging violation of both the Sherman Act and RICO, fraud, and, with respect to Puget Energy, Inc. and Puget Sound Energy, Inc., breach of contract. The complaint alleges that the price of electric energy purchased by the Port between November 1997 and June 2001 under a contract with Puget Sound Energy, Inc. was unlawfully fixed and artificially increased through various actions alleged to have been undertaken in the Pacific Northwest power markets among the defendants and ENE, EES, ENA, EPMI, and others. The complaint alleges actual damages of $30.5 million suffered by the Port and seeks recovery of that amount, plus punitive damages and reasonable attorney fees. PGE, along with other defendants, filed with the Judicial Panel on Multidistrict Litigation a notice of tag-along action on June 17, 2003. Port of Seattle, Puget Energy, Inc., Pugent Sound Energy, Inc., and PacificCorp are opposed to the notice. PGE joined in a motion to dismiss on federal preemption and filed rate doctrine grounds.

10. Remington et al. v. Northwestern Energy, LLC (No. DV 03-88, 2nd Judicial District, Silver Bow County, Montana). On May 5, 2003, Robert and Julie Remington and forty-eight other individuals, unions, and businesses filed a suit against PGE and the other owners, designers and operators of the Colstrip coal-fired electric generation plants in Montana alleging that holding and settling ponds at the Colstrip Project have leaked and contaminated groundwater. The plaintiffs allege nuisance, trespass, unjust enrichment, fraud, and negligence, and seek a declaratory judgment of nuisance and trespass, an order that the nuisance be abated, and an unspecified amount for damages, disgorgement of profits, and punitive damages.

11. California Electricity Refund Proceeding (FERC Docket # EL00-95). In a June 19, 2001 order adopting a price mitigation program for 11 states within the WSCC area, FERC referred the issue of refunds for spot market sales made from October 2, 2000 through June 20, 2001 to a settlement judge. On July 25, 2001, FERC issued an order establishing the scope of and methodology for calculating refunds related to non-federally mandated transactions in the spot markets operated by the ISO and the PX. PGE's potential refund obligation, using FERC methodology, is estimated to be in the range of $20 million to $30 million. On March 26, 2003, FERC issued an order modifying the methodology it had previously ordered for the pricing of natural gas in calculating the amount of potential refunds. Although further proceedings will be necessary to determine exactly how the new methodology will affect the refund liability, PGE now estimates its potential liability to be between $20 million and $50 million. PGE joined a group of utilities in filing a request for rehearing of various aspects of the March 26, 2003 order, including the pricing of the gas cost component of the proxy price from which refunds are to be calculated. The FERC issued an order affirming the new methodology on October 16, 2003.

12. Pacific Northwest Refund Proceeding (FERC Docket # EL01-10). Refer to Section IV.C.1.e(i)(C)(2), "Puget Sound Energy Inc. v. All Jurisdictional Settlers of Energy et al., including EPMI, as well as PGE. Docket No. EL01-10 et seq., (Pacific Northwest Refund Proceeding)" for further information.

13. Oregon Public Utility Commission Staff Report on Trading Activities. On April 29, 2003, the Staff of the OPUC issued a draft report in which it recommended that the OPUC affirm that it will hold harmless the customers of PGE in the event any penalties are imposed by FERC or any other authority investigating PGE's trading activities and that the OPUC open a formal investigation of PGE's trading activity in 2000-01. On June 12, 2003, the OPUC delayed any decision on commencing an investigation of PGE's trading activities until after FERC has substantially completed its inquiry of PGE trading activities. On September 26, 2003, PGE and OPUC, as part of PGE's settlement with the Staff of FERC and others related to certain investigations and cases related to electricity prices in California in 2000-2001, entered into a settlement agreement that resolves any issues related to this investigation. The settlement has been submitted to FERC for approval. Refer to Section VIII.C.14., "FERC Investigation of Trading Activities" for further information.

14. FERC Investigation of Trading Activities. In early May 2002, ENE provided memos to FERC that contained information indicating that ENE, through its subsidiary EPMI, may have engaged in several types of trading strategies that raised questions regarding potential manipulation of electricity and natural gas prices in California in 2000-2001. In August 2002, FERC initiated investigations into instances of possible misconduct by PGE and certain other companies. In Docket No. EL02-114-000, FERC ordered investigation of PGE and EPMI related to possible violations of their codes of conduct, FERC's standards of conduct, and the companies' market-based rate tariffs. In the order, FERC established October 15, 2002 as the "refund effective date." If PGE were to lose its market-based rate authority, purchasers of electric energy from PGE at market-based rates after the refund effective date could be entitled to a refund of the difference between the market-based rates and cost-based rates deemed just and reasonable by FERC. On September 26, 2003, PGE entered into a settlement agreement with the Staff of FERC, the California Attorney General, the California Public Utilities Commission, the City of Tacoma, Washington, OPUC and numerous other parties resolving this investigation and related cases and investigations. The settlement requires PGE to pay $8.5 million and file an amendment to its FERC market-based rates tariff that imposes a cost-based cap on prices charged for wholesale electricity sales for a period of twelve months, but does not require any refunds. PGE also agreed to conduct annual training for its trading floor employees on code of conduct, standards of conduct, antitrust and ethics, and to retain for five years recordings of affiliate trading transactions, affiliate postings and related accounting records. The settlement provides that it will not be deemed an admission of fault or liability by PGE for any reason and implies no admission or fault by PGE. The settlement has been submitted to FERC for approval.

15. Challenge of the California Attorney General to Market-Based Rates. Refer to Section IV.C.1.e(i)(C)(6), "Challenge of the California Attorney General to Market-Based Rates" for further information.

16. Show Cause Order. On June 25, 2003, FERC voted to require over 50 entities, including PGE, that participated in the western U.S. wholesale power market in 2000 and 2001 to show cause why their participation in specific behaviors and activities during that time period did not constitute gaming in violation of tariffs issued by the ISO and the PX. The ISO was ordered to provide data on each entity's behaviors and activities within 21 days from the date of the order. On August 27, 2003, PGE and FERC trial staff filed a settlement with the

Administrative Law Judge and requested that the settlement be certified to the FERC. The settlement requires PGE to pay $12,730 as revenue received in one identified behavior. This settlement is one of numerous such settlements by the entities being investigated. All of the settlements have been contested by certain parties to the proceeding. Refer to Section IV.C.1.e(i)(A)(4), "American Electric Power Services Corp., et al., Docket Nos. EL03-137-000, et al." for further information.

17. People of the State of Montana, ex rel. Mike McGrath, Attorney General of the State of Montana, et al. v. Williams Energy Marketing and Trading Company, et al. including EESI, EPMI and PGE, Montana First Judicial District, Lewis and Clark County. On June 30, 2003 the Montana Attorney General filed a complaint in Montana state court against PGE and numerous named and unnamed generators, suppliers, traders, and marketers of electricity and natural gas in Montana. The complaint alleges unfair and deceptive trade practices in violation of the Montana Unfair Trade and Practices and Consumer Protection Act, deception, fraud and intentional infliction of harm arising from various actions alleged to have been undertaken in the western wholesale electricity and natural gas markets during 2000 and 2001. The relief sought includes injunctive relief to prohibit the unlawful practices alleged, treble damages, general damages, interest, and attorney fees. No monetary amount is specified. This case was removed to federal district court and a subsequent filing with the Judicial Panel on Multidistrict Litigation is pending. Montana has filed a motion for remand.

18. ISO and PX Receivable. As of March 31, 2003, PGE was owed approximately $62 million from the ISO and the PX for wholesale electricity sales made from November 2000 through February 2001. PGE estimates that the majority of this amount was for sales by the ISO and PX to Southern California Edison Company and PG&E. On March 9, 2001, PX filed for bankruptcy, and on April 6, 2001, PG&E also filed for bankruptcy relief. PGE is pursuing collection of all past due amounts through the PX and PG&E bankruptcy proceedings, and has filed a proof of claim in each case. PGE is examining its options with regard to collection of any amounts not ultimately received through the bankruptcy process. To the extent that PGE is found liable for refunds in the FERC California Refund proceeding, PGE will be entitled to offset that amount against the $62 million receivable.

19. FERC Bidding Investigation. On June 25, 2003, FERC issued an order initiating an investigation into anomalous bidding in the California markets. PGE submitted responses on July 24, 2003 and August 11, 2003 and is continuing its analysis of bid data relevant to the investigation. Refer to Section IV.C.2.b(iii)., "FERC Bidding Investigation" for further information about the investigation.

D. Description of Capital Stock, Board of Directors and Director and Officer Indemnification

The information set forth below is summarized from PGE's Articles of Incorporation, as amended. The statements and description hereinafter contained do not purport to be complete and are qualified in their entirety by references to the Articles of Incorporation.

1. Capital Stock

a. Common Stock. PGE currently has outstanding 42,758,877 shares of common stock, par value of $3.75 per share, all of which are owned by ENE. Upon satisfaction of the conditions for distribution of PGE Common Stock to the Creditors pursuant to the Plan, as described in Section I., "Overview of Chapter 11 Plan", such existing common stock of PGE held by ENE will be cancelled, and the new PGE Common Stock will be issued.

b. Preferred Stock. PGE currently has outstanding 279,727 shares of its 7.75% Series Cumulative Preferred Stock, no par value. The outstanding preferred stock has a voluntary and involuntary liquidation preference of $100.00 per share, and pays a dividend of $7.75 per share quarterly on the 15th of January, April, July and October. It is redeemable only by operation of a sinking fund that requires the annual redemption of 15,000 shares at $100 per share, plus all accrued and unpaid dividends, each year commencing on June 15, 2002 for five years, with all remaining shares to be redeemed on June 15, 2007. At its option, PGE may redeem, through the sinking fund, an additional 15,000 shares each year, but such optional redemption is not cumulative and does not reduce any subsequent mandatory redemption. The sinking fund may be satisfied in whole or in part by crediting shares purchased by PGE in the open market or otherwise. The 7.75% Series Cumulative Preferred Stock generally has no voting rights but may, in certain circumstances, vote to elect a limited number of PGE directors. Such preferred stock will remain outstanding upon the issuance of the PGE Common Stock to the Creditors. PGE also has the right, with the approval of its board of directors, to issue additional series of preferred stock. Such preferred stock will remain outstanding upon the issuance of the PGE Common Stock to the Creditors.

c. Limited Voting Junior Preferred Stock. On September 30, 2002, a single share of a new class of Limited Voting Junior Preferred Stock was issued by PGE to an independent party. The new class of stock, created by an amendment to PGE's Articles of Incorporation, was issued following approval by the Bankruptcy Court on September 12, 2002, the DIP Lenders, the OPUC, and PGE's board of directors.

The Limited Voting Junior Preferred Stock has a par value of $1.00, no dividend, a liquidation preference to PGE's common stock as to par value but junior to existing preferred stock, an optional redemption right, and certain restrictions on transfer. The Limited Voting Junior Preferred Stock also has voting rights, which limit, subject to certain exceptions, PGE's right to commence any voluntary bankruptcy, liquidation, receivership, or similar proceedings without the consent of the holder of the share of Limited Voting Junior Preferred Stock. The consent of the holder of the share of Limited Voting Junior Preferred Stock will not be required if the reason for the bankruptcy or similar event is to implement a transaction pursuant to which all of PGE's debt will be paid or assumed without impairment. Such preferred stock will remain outstanding upon the issuance of PGE Common Stock to the Creditors.

2. PGE Board of Directors

On the Effective Date, PGE's board of directors will consist of individuals designated by the Debtors (after consultation with the Creditors' Committee), all of which shall be disclosed prior to the Confirmation Hearing. In the event that, during the period from the Confirmation Date up to and including the Effective Date, circumstances require the substitution of one (1) or more persons selected to serve, the Debtors shall file a notice thereof with the

Bankruptcy Court and, for purposes of section 1129 of the Bankruptcy Code, any such replacement person, designated after consultation with the Creditors' Committee, shall be deemed to have been selected or disclosed prior to the Confirmation Hearing. Thereafter, the terms and manner of selection of directors of PGE shall be as provided in PGE's certificate of incorporation and bylaws, as the same may be amended.

3. Indemnification

PGE is organized under the laws of the State of Oregon. Under PGE's Articles of Incorporation, PGE will indemnify directors and officers of PGE to the fullest extent permitted by the Oregon law. Expenses incurred by a director or officer in connection with an indemnifiable claim will be addressed by PGE provided that such director or officer will obligate himself/herself to repay such advance to the extent it is ultimately determined that such director or officer was not entitled to indemnification. PGE is authorized to provide the same indemnification protections to employees and agents.

PGE has procured Directors and Officers liability insurance for wrongful acts. This is an indemnity policy for the corporation to protect it against liability assumed or incurred under the above indemnification provisions, including defense provisions, on behalf of the directors and officers. The directors and officers are thus indemnified against loss arising from any civil claim or claims by reason of any wrongful act done or alleged to have been done while acting in their respective capacities as directors or officers. The policy excludes claims brought about or contributed to by dishonest, faudulent, criminal, or malicious acts or omissions by directors or officers. The policy covers the directors and officers of PGE against certain liabilities, including certain liabilities arising under the Securities Act, which might be incurred by them in such capacities and against which they cannot be indemnified by PGE.

E. Equity Compensation Plan

Following confirmation of the Plan, in order to attract, retain and motivate highly competent persons as key employees and/or directors of PGE, PGE expects to adopt a long-term equity incentive compensation plan providing for awards to such individuals. It is anticipated that the Compensation Committee of PGE's Board of Directors will determine the specific terms of any grants made under such plan and will provide grants of awards designed to focus equity compensation on performance and alignment with shareholders interests; provided, however, that shares reserved for the plan will not exceed 7.5% of the PGE Common Stock to be issued pursuant to the Plan, with projected annual share usage under the plan not exceeding 2%.

IX. CrossCountry Energy Corp.

Capitalized terms used throughout this Disclosure Statement are defined in Appendix A: "Material Defined Terms for Enron Disclosure Statement" attached hereto.

A. Business

1. General Development of Business

On September 25, 2003, the Bankruptcy Court entered an order approving a transaction that would transfer ENE's direct and indirect ownership interests in the Pipeline Businesses and certain service companies to a new holding company called "CrossCountry Energy Corp." The direct and indirect interests in the Pipeline Businesses and related service companies owned by ENE and certain of its affiliates will be exchanged for shares of common stock in CrossCountry pursuant to the terms of the CrossCountry Contribution and Separation Agreement entered into on June 24, 2003. The closing of the transactions contemplated by the CrossCountry Contribution and Separation Agreement is expected to occur in the fourth quarter of 2003. Refer to Section IX.F., "Certain Relationships and Related Transactions" for further information.

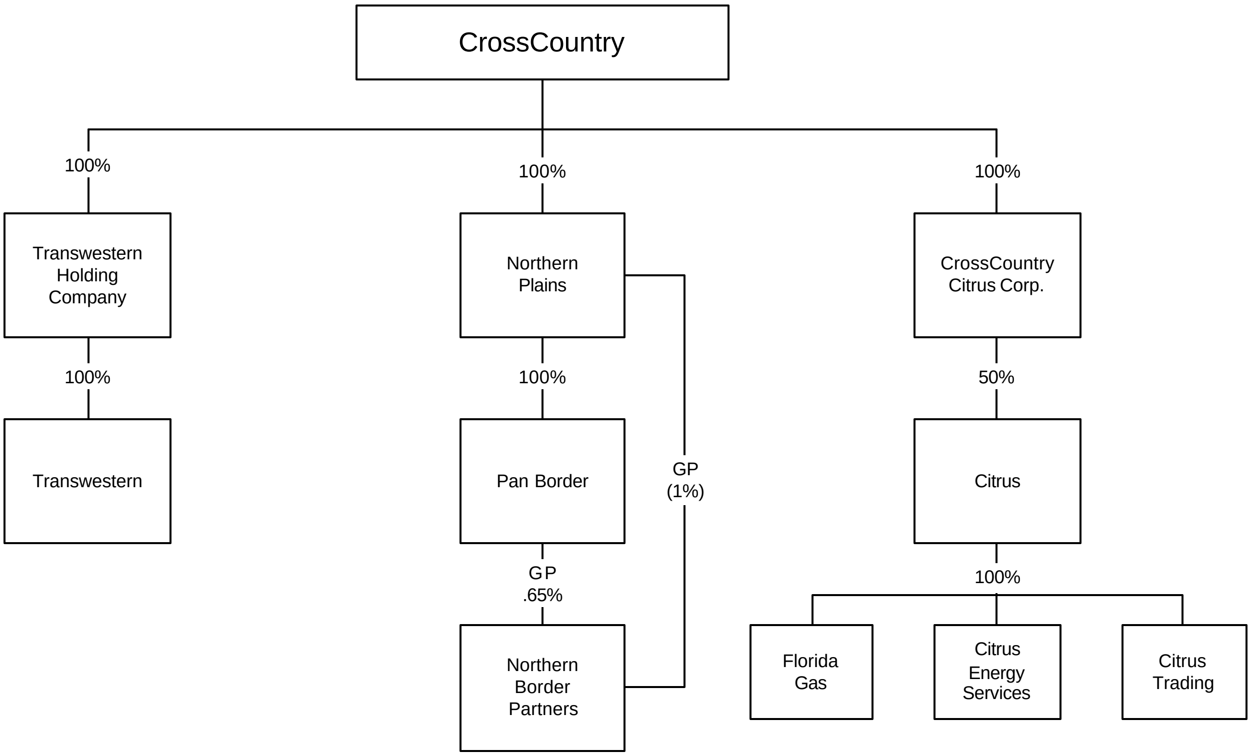
CrossCountry's principal assets will, upon closing of the formation transactions, consist of the following:

- A 100% ownership interest in Transwestern, which owns an approximately 2,600-mile interstate natural gas pipeline system that transports natural gas from western Texas, Oklahoma, eastern New Mexico, the San Juan basin in northwestern New Mexico and southern Colorado to California, Arizona, and Texas markets. Transwestern's net income for the year ended December 31, 2002 was $20.7 million.

- A 50% ownership interest in Citrus, a holding company that owns, among other businesses, Florida Gas, a company with an approximately 5,000-mile natural gas pipeline system that extends from southeast Texas to Florida. An affiliate of CrossCountry operates Citrus and certain of its subsidiaries. Citrus's net income for the year ended December 31, 2002 was $96.6 million, 50% of which, or $48.3 million, comprised ENE's equity earnings. CrossCountry is expected to hold its interest in Citrus through its wholly owned subsidiary, CrossCountry Citrus Corp.

- A 100% interest in Northern Plains, which directly or through its subsidiaries holds 1.65% out of an aggregate 2% general-partner interest and a 1.06% limited-partner interest in Northern Border Partners, a publicly traded limited partnership (NYSE: NBP), that is a leading transporter of natural gas imported from Canada to the midwestern United States. Pursuant to operating agreements, Northern Plains operates Northern Border Partners' interstate pipeline systems, including Northern Border Pipeline, Midwestern, and Viking. Northern Border Partners also has (i) extensive gas gathering operations in the Powder River Basin in Wyoming, (ii) natural gas gathering, processing and fractionation operations in the Williston Basin in Montana and North Dakota, and the western Canadian sedimentary basin in Alberta, Canada, and (iii) ownership of the only coal slurry pipeline in operation in the United States. Northern Border Partners' net income for the year ended December 31, 2002 was $113.7 million, of which $9.1 million comprised ENE's equity earnings.

CrossCountry Ownership Structure after Contribution of Pipeline Businesses

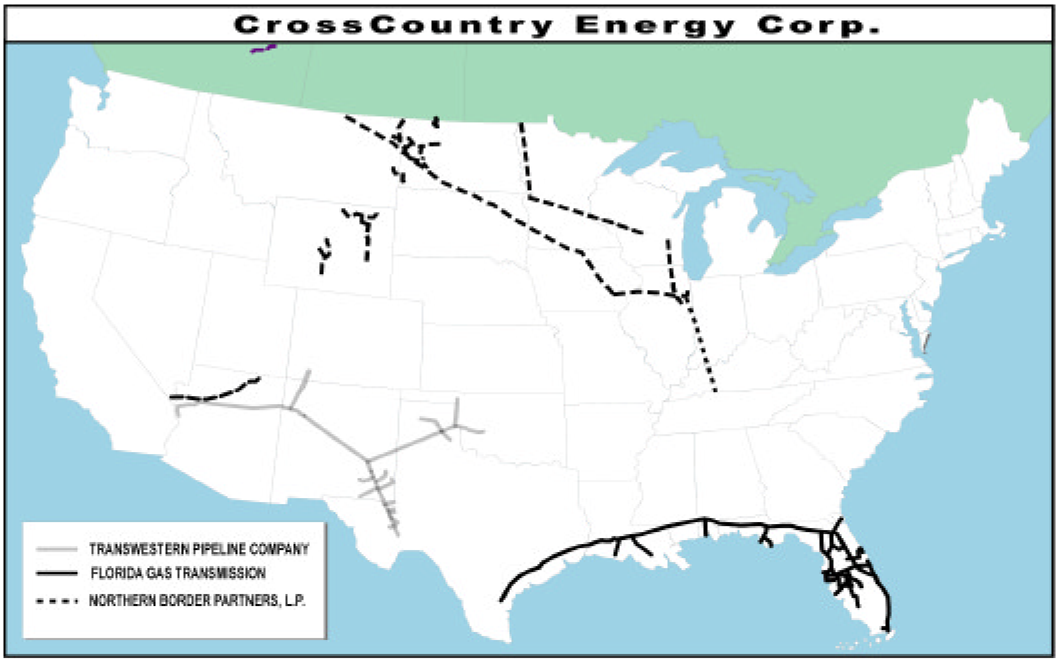


The Pipeline Businesses primarily provide natural gas transportation services to their customers through an extensive North American pipeline infrastructure. The Pipeline Businesses own or operate interstate pipelines that have a combined daily throughput capacity of approximately 8.5 TBtu/d (8.6 TBtu/d after completion of Florida Gas Phase VI Expansion described below) spanning approximately 9,900 miles and accessing many of the major gas supply and market growth-oriented regions in North America.

The interstate Pipeline Businesses provide firm and interruptible transportation services to third-party shippers, as well as hub services, which allow customers the ability to park or borrow volumes of gas on a pipeline. Firm shippers that contract for the stated transportation rate are obligated to pay a monthly demand charge, regardless of the amount of natural gas they actually transport, for the term of their contracts. Interruptible transportation service is transportation of natural gas in circumstances where capacity is available after satisfying firm service demands. If weather, maintenance schedules and other conditions allow, the interstate Pipeline Businesses provide interruptible transportation service. The interstate Pipeline Businesses do not own the gas that they transport and therefore do not assume natural gas commodity price risk for quantities transported. The Pipeline Businesses, however, assume limited price risk for volumes provided by customers as fuel reimbursement pursuant to FERC tariffs.

Following the closing of the formation transactions, CrossCountry will reflect its investments in Citrus and Northern Border Partners under the equity method of accounting. Accordingly, CrossCountry will report its share of Citrus's and Northern Border Partners' earnings as "Equity in Earnings" in its Consolidated Statement of Operations in the period in which such earnings are reported by Citrus and Northern Border Partners.

The following map shows facilities to be owned or operated by CrossCountry after the contribution of the Pipeline Businesses.



CrossCountry's executive offices are located at 1400 Smith Street, Houston, Texas 77002 and its telephone number is 713-853-6161.

a. Business Strategy. CrossCountry's business strategy will be comprised of two major components. First, CrossCountry plans to seek out new pipeline gathering, processing or storage projects to match its customers' future needs and to provide supply optionality. CrossCountry will undertake such expansion projects when they are adequately backed by capacity contract commitments that result in reasonable returns being earned. Second, CrossCountry plans to seek out acquisitions that are immediately accretive to both cash flow and income. In executing its business strategy, CrossCountry plans to operate its pipeline, gathering and processing businesses in compliance with all applicable regulations to assure the safe operations of its pipeline systems, and will aim to provide reliable services at a reasonable cost.

CrossCountry should be well-positioned to implement its planned strategy, but will face risks both specific to its assets and general to the markets and geographic regions in which it will operate. In addition to Bankruptcy Court approval, the transfer of the Pipeline Businesses and distribution of CrossCountry Common Stock to Creditors may require consent of other parties. Refer to Section XIV.H., "CrossCountry" for further information on risk factors that should be carefully considered.

(i) Expansions. The interstate Pipeline Businesses have a history of expanding their pipeline systems to meet growth in market demand and to increase customers' access to additional natural gas supplies. These expansions not only provide the individual interstate Pipeline Businesses with additional net income and cash flow, but also are important factors in maintaining and enhancing their market positions. Historically, the interstate Pipeline Businesses have undertaken expansions when they are backed by long-term firm contract commitments. Refer to Section XIV.H.1.a., "Execution of Growth Strategy" for further information.

Since 1992, Transwestern has added and expanded various pipeline segments, including the construction of a 520 BBtu/d San Juan lateral and the expansion of its mainline capacity at a cost of $270 million. In addition, Transwestern added: (i) 330 BBtu/d of capacity off the eastern portion of its system at a cost of $10.1 million; (ii) 420 BBtu/d of capacity from Blanco (a point in New Mexico) to Thoreau (a point in New Mexico) at a cost of $26.0 million; (iii) 200 BBtu/d of capacity from Ignacio (a point in Colorado) to Blanco at a cost of $7.3 million; and (iv) 120 BBtu/d of capacity on its mainline west segment (Arizona and California delivery) at a cost of $69.7 million.

Since 1995, Florida Gas has completed, or is in the process of completing, four major expansion projects. These expansion projects, which have cost $1.8 billion, have increased delivery capacity to the Florida market by approximately 1.3 TBtu/d.

Since 1992, Northern Border Pipeline completed three expansion projects at a cost of $1.1 billion, which extended its system from Ventura, Iowa into Illinois and Indiana and added 1.6 TBtu/d of capacity to various parts of its system.

CrossCountry anticipates that it will undertake future strategic expansions of the interstate Pipeline Businesses' pipeline systems to maintain and enhance its market position. Refer to Sections IX.A.2.a., "Transwestern" and IX.A.2.b., "Citrus" for further information.

(ii) Acquisitions. As a result of favorable tax advantages afforded master limited partnerships and the incentive distribution provisions of Northern Border Partners' partnership agreement, CrossCountry anticipates that Northern Border Partners will serve as one of CrossCountry's principal vehicles for the future acquisition of energy assets. Refer to Section XIV.H.1.a., "Execution of Growth Strategy" for further information.

Under the incentive distribution provisions of the Northern Border Partners partnership agreement, the general partners are entitled to incentive distributions if the amount distributed in any quarter exceeds $0.605 per common unit ($2.42 per common unit annualized). The general partners are entitled to 15% of amounts distributed in excess of $0.605 per common unit, 25% of amounts distributed in excess of $0.715 per common unit ($2.86 per common unit annualized) and 50% of amounts distributed in excess of $0.935 per common unit ($3.74 per common unit annualized). Thus, acquisitions that meet the investment criteria of Northern Border Partners and are accretive to Northern Border Partners' cash flows could offer CrossCountry attractive yields if these acquisitions enable Northern Border Partners to increase its quarterly distributions.

Over the past three years Northern Border Partners has increased its quarterly distribution per common unit by 23% from $0.65 per common unit to $0.80 per common unit.

Over the same time period, Northern Border Partners has made acquisitions totaling $920 million. These acquisitions include 100% of the stock of Midwestern and Viking, including a one-third interest in Guardian and extensive gathering and processing facilities in the Rocky Mountain area.

Transwestern and Florida Gas have historically made acquisitions to meet market growth and gain access to gas supplies. Since 1995, Transwestern acquired the Ignacio to La Plata pipeline capacity for $20.6 million and Florida Gas acquired supply line facilities in the Mobile Bay area for $49.4 million.

b. Employees and Pipeline Services. As of September 30, 2003, the proposed consolidated subsidiaries of CrossCountry (Transwestern, Pan Border, Transwestern Holding, Northern Plains, CGNN, CrossCountry Citrus Corp., and NBP Services) had 785 full-time employees, none of whom were represented by unions or covered by collective bargaining agreements. In addition, Citrus, Florida Gas, Citrus Trading and certain subsidiaries of Northern Border Partners have their own employees.

It is anticipated that CrossCountry and ENE will enter into a Transition Services Agreement and a Transition Services Supplemental Agreement in connection with the formation of CrossCountry, pursuant to which ENE will provide to CrossCountry, on an interim, transitional basis, certain administrative, technology and other services. Refer to Section IX.F., "Certain Relationships and Related Transactions" for further information.

CGNN provides certain administrative and operating services to the Pipeline Businesses. These services include environmental, right-of-way, safety, information technology, accounting, planning, finance, procurement, accounts payable, human resources, and legal services. Each of the Pipeline Businesses reimburses CGNN for its costs for rendering these services, depending on the service provided to such pipeline. Costs may be billed based upon dedicated headcount, time spent providing the service, miles of pipeline, payroll, assets, margins, and/or overall headcount.

EOS or its affiliates, including CGNN, provides services to Citrus and its subsidiaries under an operating agreement originally entered into between an ENE affiliate and Citrus. The primary term of the operating agreement expired on June 30, 2001; however, services continue to be provided pursuant to the terms of the operating agreement. Under this arrangement, Citrus reimburses the service provider for costs attributable to the operations of Citrus and its subsidiaries. There can be no assurance that the parties will continue to perform under this arrangement.

Northern Plains provides operating services to the Northern Border Partners pipeline system pursuant to operating agreements entered into with Northern Border Pipeline, Midwestern, and Viking. Under these agreements, Northern Plains manages the day-to-day operations of Northern Border Pipeline, Midwestern, and Viking, and is compensated for the salaries, benefits, and other expenses it incurs. Northern Plains also utilizes ENE affiliates for administrative and operating services related to Northern Border Pipeline, Midwestern, and Viking.

NBP Services provides certain administrative and operating services for Northern Border Partners and its gas gathering and processing and coal slurry businesses. NBP Services is reimbursed for its direct and indirect costs and expenses pursuant to an administrative services agreement with Northern Border Partners. NBP Services also utilizes ENE affiliates to provide these services.

2. Narrative Description of Business

a. Transwestern. Transwestern owns and operates an approximately 2,600-mile interstate natural gas pipeline system with diameters ranging from twelve inches to thirty inches, and approximately 350 miles of small diameter branchlines. The Transwestern pipeline system transports natural gas from western Texas, Oklahoma, eastern New Mexico, and the San Juan basin in northwestern New Mexico and southern Colorado primarily to California and southwest markets and to markets off the east end of its system. The Transwestern pipeline system consists of mainlines that stretch from west Texas and Oklahoma to the California border. In addition, Transwestern has a major supply lateral from its mainline facilities at Thoreau, New Mexico into the San Juan basin. The Transwestern pipeline system has bi-directional flow capability from the San Juan basin eastward to interconnects with interstate pipelines serving the mid-continent markets and Texas intrastate pipelines. The Transwestern pipeline system has approximately 360 receipt and delivery points in California, Arizona, Colorado, New Mexico, Oklahoma, and Texas. It also has 29 mainline and lateral compressor stations. The maximum allowable operating pressure of the mainline ranges from 1,000 to 1,200 psig.

In 2003, Transwestern's total revenues are projected to be 85% from fixed sources (*i.e.*, demand charges, which are fixed charges for transportation services that are paid even if no service is taken by the customer) and 15% from variable sources of revenues (including operational gas sales and transportation commodity charges, which are charges assessed on each unit of transportation provided).

Transwestern's business plan contemplates managing the quantity of line pack gas to maintain safe and efficient operations. "Line pack gas" refers to the volume of gas in a pipeline system used to maintain pressure and effect uninterrupted flow of gas to customers. Transwestern makes operational gas available for sale when reduced line pack is appropriate for system operations. A primary source of the operational gas available for sale is gas provided to Transwestern by its shippers as reimbursement for compressor fuel usage. When, due to throughput conditions, flow direction or operating efficiencies, Transwestern is able to consume less fuel than retained, such gas remains in the line pack and, if not needed for operations, becomes available for sale. Transwestern's FERC-approved tariff specifies the fuel quantity for each segment of the system as a fixed percentage of a shipper's transportation quantities. Operational sales comprised approximately 18% of revenues in 2001 and 14% of revenues in 2002 and are projected to constitute approximately 10% of revenues in 2003.

(i) Expansions. Transwestern placed its Red Rock expansion, serving markets in California and Arizona, in-service as of June 15, 2002. Transwestern's pipeline capacity (including both eastward and westward flow) after the completion of the Red

Rock expansion is approximately 2 TBtu/d, and the total horsepower from all compressor stations is approximately 330,500 hp.

In August 2001, Transwestern conducted an open season to solicit interest in a project to construct a lateral line extending from the Transwestern mainline 176 miles south to serve growing gas markets in the Phoenix, Arizona area. The original project also contemplated San Juan and mainline expansions. Transwestern received non-binding bids for over 440 BBtu/d for the Phoenix lateral pipeline. Many of the potential bidders are parties to an ongoing FERC allocation dispute on El Paso Natural Gas's pipeline system in FERC Docket No. RP00-336. Due to delays in this proceeding, several of the bidders have been unable to finalize their firm bids for a Transwestern Phoenix lateral pipeline. Transwestern continues to believe that such a proposed expansion project is important and economically viable to be placed into service in 2007; however, no assurances can be given that the project will be completed.

In March 2003, Transwestern conducted an open season to solicit interest in the expansion of the San Juan lateral pipeline from the Blanco Hub to the mainline from its current capacity of approximately 860 BBtu/d. Transwestern received non-binding bids requesting approximately 750 BBtu/d of capacity. Current project plans call for the completion of binding agreements during the second half of 2003, filing of a FERC certificate in the first quarter of 2004, construction in late 2004, and a projected in-service date in July 2005. The proposed 375 BBtu/d expansion will include looping of existing pipeline segments and additional horsepower at existing compressor stations.

(ii) Customers. Transwestern's pipeline capacity, as of July 1, 2003, was held by producers (45%), local distribution companies (31%), marketing companies (21%), and end-users (3%). Currently, Transwestern's pipeline capacity for both west and east flow is subscribed under a combination of short- and long-term contracts. Historically, approximately 90% of the volumes scheduled on the Transwestern pipeline system has been on a firm transportation basis.

Transwestern's largest customers in 2002 were Southern California Gas Company, PG&E, and BP Energy Company. Southern California Gas Company accounted for 29.4% of Transwestern's transportation revenues under transportation agreements with terms that extend through October 31, 2005. PG&E accounted for 9.7% of Transwestern's transportation revenues, and BP Energy Company accounted for 9.0% of Transwestern's transportation revenues. Refer to Section XIV.H.1.e., "Concentrated Gas Transportation Revenues" for further information.

Transwestern's capacity is subscribed at a high level through October 31, 2005, with significant contract expirations timed to coincide at or near Transwestern's next rate case in 2006. In 2003, Transwestern's mainline west segment is expected to account for approximately 70% of Transwestern's firm transportation revenues. As of July 1, 2003, approximately 94% of Transwestern's firm capacity for its mainline west segment was under contract through January 1, 2004, 90% through January 1, 2005, 76% through January 1, 2006 and 40% through the end of 2006. In 2003, Transwestern's San Juan lateral segments are expected to account for approximately 20% of Transwestern's firm transportation revenue. As of July 1, 2003, approximately 100% of Transwestern's firm capacity for its San Juan lateral segments was under contract through January 1, 2004, 99% through January 1, 2005, 88% through January 1, 2006 and 47% through the end of 2006. In addition, Transwestern has significant firm contracts for eastward flow to markets in Texas and Oklahoma, but historically these contracts have not been on a long-term basis. Approximately 100% of eastward flow firm capacity is under contract through 2004. Refer to Section XIV.H.1.d: "Maintenance and Expiration of Transportation Service Agreements" for further information.

In 2001, the California power market was significantly impacted by the increase in wholesale prices. On April 6, 2001, PG&E filed for bankruptcy protection under chapter 11 of the Bankruptcy Code. This event had no material impact on the financial position or results of operations of Transwestern for the year ended December 31, 2002. Transwestern continues to provide transportation services to PG&E on a prepayment basis. CrossCountry cannot predict the final outcome of this situation or the uncertainties surrounding the California power situation. However, CrossCountry does not anticipate that these matters will have a material adverse impact on Transwestern's financial position or results of operations.

(iii) Supply. The Transwestern pipeline system has access to three significant supply basins for its gas supply: (1) the San Juan basin in northwestern New Mexico and southern Colorado, (2) the Permian basin in western Texas and eastern New Mexico, and (3) the Anadarko basin in the Texas and Oklahoma Panhandles. Additionally, the Transwestern pipeline system can access gas from the Rocky Mountain basin through its pipeline interconnections.

Through its San Juan lateral pipeline, the Transwestern pipeline system is capable of delivering gas from the San Juan basin to California, Arizona, New Mexico, and southern Nevada markets, as well as to markets off the east end of its system. This bi-directional flow capability was added in 1996 to increase system flexibility and utilization. New in-fill drilling programs approved by the New Mexico Oil Conservation Division for the San Juan basin and new Rockies production are also expected to increase Transwestern's San Juan lateral utilization. The Transwestern pipeline system can also supplement the San Juan basin production with gas supply from the Rocky Mountain basin via its interconnects with Northwest Pipeline Corporation, which is owned by The Williams Companies, and the TransColorado Gas Transmission Company, which is owned by Kinder Morgan, Inc. These two interconnects combine to provide the Transwestern pipeline system with approximately 500 BBtu/d of access to Rocky Mountain supplies. Since 2000, Transwestern has added five (5) new receipt interconnects in its East of Thoreau area: (1) an approximately 80 BBtu/d interconnect with Natural Gas Pipeline Company; (2) an approximately 20 BBtu/d interconnect with EOG Resources; (3) an approximately 40 BBtu/d interconnect with El Paso Field Services; (4) an approximately 120 BBtu/d interconnect with Agave Energy Company; and (5) an approximately 150 BBtu/d interconnect with NNG. In addition, a new approximately 50 BBtu/d interconnect, as well as an approximately 100 BBtu/d expansion of an existing interconnect, with Red Cedar Gathering, were completed in the San Juan basin area in 2001.

In June 2003, the bi-directional Rio Puerco interconnect with Public Service Company of New Mexico was expanded by approximately 50 BBtu/d. This dual purpose point allows Transwestern to receive more San Juan gas supply from Public Service Company of New Mexico in the summer and increase deliveries to it during peak winter months.

In July 2003, Transwestern completed the facilities necessary to provide shippers direct access to underground storage capacity. This 2 TBtu storage facility, owned by UnoCal Keystone Gas Storage, LLC, has the ability to deliver to Transwestern or receive from Transwestern up to 100 BBtu/d.

b. Citrus. Citrus serves as the holding company for Florida Gas, Citrus Trading, and Citrus Energy Services. The Florida Gas pipeline system currently extends for approximately 5,000 miles from southeast Texas through the Gulf Coast region of the United States to southeastern Florida, with a pipeline also extending to the west coast of Florida, including the Tampa, St. Petersburg, and Ft. Myers areas. The Florida Gas pipeline system includes 29 mainline and field compressor stations with approximately 487,980 hp of compression (approximately 507,000 hp of compression upon the completion of the Phase VI Expansion). Florida Gas's pipeline system is designed to transport approximately 2.1 TBtu/d of natural gas to the State of Florida during periods of peak demand.

Florida Gas has two marketing regions: the Western Division, representing Texas, Louisiana, Mississippi and Alabama, and the Market Area, representing Florida. Western Division transport charges are mileage-based rates. Market Area division transport charges are postage stamp rates, meaning the customer can transport on Florida Gas's pipeline system at a fixed rate regardless of receipt point or delivery point into Florida.

Citrus Trading purchases and sells natural gas to end users in Florida. It currently has contracts to purchase and sell approximately 42 BBtu/d of natural gas. Citrus Trading sells gas to two customers at the present time. Citrus Trading's gas purchase contract with Duke Energy LNG is the subject of a dispute, and each party has provided notice of termination of the contract. Refer to Section IX.D., "Legal Proceedings", for further information. Citrus Trading sells gas to Auburndale Power Partners, LP and Progress Energy Florida, Inc., and buys gas through El Paso Merchant Energy, an affiliate of Southern Natural Gas. Refer to Section XIV.H.4.a., "Citrus Trading Contract Risk" for further information.

Citrus Trading makes sales pursuant to a blanket marketing certificate issued by FERC. The prices charged by Citrus Trading are not currently regulated by FERC. In a prior FERC proceeding, FERC had threatened to revoke Citrus Trading's blanket certificate, which would have prevented Citrus Trading from making sales for resale in interstate commerce at market rates, as opposed to cost-based rates (although Citrus Trading could make direct sales to end-users at market rates). By order dated June 25, 2003, FERC dismissed Citrus Trading from the proceeding, taking no action against it.

Citrus Energy Services is primarily in the business of providing operations and maintenance services to customers of Florida Gas and Citrus Trading. Due to increased insurance costs and pipeline integrity legislation that affects operators, Citrus Energy Services is in the process of exiting this business. The majority of the personnel operating Citrus Energy Services are direct employees of Florida Gas and to a lesser extent Citrus. Certain ENE entities provide management and support services to Citrus and its subsidiaries through an operating agreement that expired on June 30, 2001. Refer to Section IX.A.1.b., "Employees and Pipeline Services" for further information. Refer to Section XIV.H., "CrossCountry" for further information about Citrus and its subsidiaries.

(i) **Expansions**.

(A) **Phase V Expansion**. In April 2003, Florida Gas completed its Phase V Expansion, which added approximately 167 miles of pipeline and approximately 133,000 hp of additional compression. The Phase V Expansion increased the Florida Gas pipeline system's capacity by approximately 428 BBtu/d. The cost of this project is estimated to be approximately $425 million, and is supported by incremental long-term firm transportation service agreements for substantially all incremental peak period capacity. As part of Florida Gas's Phase V Expansion, it acquired an undivided interest in Gulf South Pipeline Company's Mobile Bay lateral pipeline. This undivided interest gives the Florida Gas pipeline system approximately 300 BBtu/d of firm receipt capacity on the Mobile Bay lateral pipeline. This purchase was closed in March 2002, to coincide with the in-service date of the first stage of the Phase V Expansion, which occurred in April 2002. Additionally, Florida Gas constructed the necessary facilities to connect this lateral pipeline to its mainline in Mobile County, Alabama.

(B) **Phase VI Expansion**. Florida Gas is in the process of constructing approximately 33 miles of pipeline and approximately 18,600 hp of additional compression at existing compression stations, which will increase its summer capacity by approximately 121 BBtu/d. This expansion is estimated to cost approximately $100 million upon completion and is supported by incremental long-term firm transportation service agreements for substantially all incremental peak period capacity. FERC issued a preliminary determination approving all non-environmental matters on February 28, 2002, and Florida Gas received a final certificate approving the Phase VI Expansion on June 13, 2002. The initial stage of its Phase VI Expansion was placed in service on June 1, 2003, and, except for certain compression modifications, the remainder of the project was completed on November 1, 2003.

(C) **Future Expansions**. Due to increasing demand for natural gas in Florida, Florida Gas continues to pursue opportunities to expand its pipeline system to meet the growing market requirements. Florida Gas is currently evaluating future system enhancements and expansions.

(ii) **Customers**. As of December 31, 2002, the Florida Gas pipeline system's peak period capacity was fully subscribed under firm transportation services agreements with approximately 140 customers. Florida Gas's pipeline system also has direct physical connections with Florida Gas's customers' local distribution systems and gas-fired electric generation facilities. Florida Gas predominantly serves two types of customers in Florida: electric generation and gas distribution. The electric generation customers, which account for approximately 80% of the total annual throughput on Florida Gas's pipeline system, have a seasonal load pattern characterized by higher summer demands, due to their air-conditioning load requirements. The gas distribution customers have a seasonal load pattern characterized by higher demands during the winter, due to the heating requirements of their residential and small commercial customers. Florida Gas also serves industrial customers in Florida that take gas at a fairly constant rate during the year, as well as industrial customers that take gas on a seasonal basis.

Florida Gas's largest customers for 2002 were Florida Power and Light Company, which contracted for approximately 45% of revenues, and TECO Energy Inc. and its affiliates, which contracted for approximately 11% of revenues. Certain of Florida Gas's contracts have contingent termination or volume reduction rights. Although CrossCountry cannot assure that these rights will not be exercised, it does not anticipate that the exercise of these rights will have a material adverse impact on the financial condition of CrossCountry. Refer to Section XIV.H.1.d., "Maintenance and Expiration of Transportation Service Agreements" for further information.

Approximately 94% of Florida Gas's revenues for 2002 were derived from the reservation revenues that the customer must pay regardless of volumes shipped. The reservation revenues are based on contracted-for transport volumes priced at the reservation tariff rate, subject to certain rate caps. The remaining 6% of revenues were usage revenues that Florida Gas's customers paid based on the volumes that were scheduled. After giving effect to the Phase VI Expansion, Florida Gas's pipeline system will have a summer-time peak load capacity of approximately 2.1 BBtu/d, with an historical average annual throughput load factor of over 85%.

Florida Gas's firm capacity is contracted at a high level through 2006. Many of Florida Gas's firm contracts have a "seasonal tilt," meaning that customers contract for a larger transportation quantity during their peak usage months than during off-peak months. Thus, Florida Gas has a larger percentage of its firm capacity under contract during the summer than during the winter. Over 90% of Florida Gas's peak capacity is fully contracted through 2010. After completion of the Phase VI expansion, Florida Gas's firm transportation agreements will have a weighted length of service in excess of 12 years.

(iii) Supply. Florida Gas's pipeline system primarily receives natural gas from natural gas producing basins in the Louisiana and Texas Gulf Coast, Mobile Bay and offshore Gulf of Mexico. In addition, Florida Gas's pipeline system operates and maintains more than 40 interconnects with major interstate and intrastate natural gas pipelines, which provide Florida Gas's customers access to most major natural gas producing regions in the contiguous 48 states of the United States and in Canada.

(iv) Citrus Governance. ENE and Southern Natural Gas, a subsidiary of El Paso, each currently owns 50% of the outstanding shares of Citrus. Following the contribution of ENE's interest in Citrus to CrossCountry Citrus Corp, Citrus will be owned equally by CrossCountry Citrus Corp and Southern Natural Gas and will be governed by a six person board of directors, three of whom will be elected by CrossCountry Citrus Corp. and three of whom will be elected by Southern Natural Gas. Significant corporate governance, administration, transactions, policy, and operational decisions that affect Citrus and its subsidiaries must be approved by the Citrus board of directors, as required under the by-laws of Citrus and its subsidiaries. EOS, as operator, is responsible under the operating agreement for the day-to-day management of Citrus and the Florida Gas pipeline system. Refer to Section IX.A.1.b., "Employees and Pipeline Services" for further information.

ENE and El Paso are deemed "Principals" under the Capital Stock Agreement, that governs ownership and disposition of the shares of Citrus. Southern Natural Gas became a party to the Capital Stock Agreement in February 2003 upon the transfer from El Paso to Southern Natural Gas of the Citrus shares held by El Paso. On October 31, 2003, ENE filed with the Bankruptcy Court, under a notice of presentment, a motion for an order approving assumption and assignment of the Capital Stock Agreement to CrossCountry or its designee. Following assumption and assignment, CrossCountry or its designee will become the Principal under the Capital Stock Agreement. The deadline for filing objections to the motion is November 17, 2003. A hearing will be held on November 20, 2003 to consider the motion. If the motion is approved, ENE will be relieved from any obligations under the Capital Stock Agreement in accordance with section 365 of the Bankruptcy Code. If the motion is denied, El Paso's consent may be required for distribution of CrossCountry Common Stock pursuant to the terms of the Plan or a sale of CrossCountry to a third party, to the extent the Capital Stock Agreement remains binding on ENE. Refer to Section XIV.A.4., "Delayed Distribution or Non-Distribution of Plan Securities" for further information.

The Capital Stock Agreement contains restrictions on the transfer of Citrus's stock. For example, a Principal, or a Subsidiary which holds the Citrus stock, may only transfer its Citrus stock to a Subsidiary, ("Subsidiary" is defined under the Capital Stock Agreement as an entity in which a Principal, either directly or indirectly, holds 100% of the capital stock entitled to vote in the election of directors). In the event that a Subsidiary of a Principal that owns Citrus stock ceases to be a Subsidiary of such Principal, the Citrus stock must be transferred back to the Principal..

In addition, the Capital Stock Agreement contains certain rights of first refusal, which provide that, subject to limited exceptions, if a Principal desires to sell its shares of Citrus stock, or the shares held by a Subsidiary of such Principal, to a non-affiliate for cash, such shares must first be offered to the other Principal, in accordance with the conditions and procedures outlined in the Capital Stock Agreement.

The Capital Stock Agreement also provides that if either Principal experiences a change of control, the other Principal, known under the Capital Stock Agreement as the "Electing Principal," will have the option:

- to purchase for cash all of the Citrus stock owned by the Principal to which the change of control relates, known under the Capital Stock Agreement as the "Non-electing Principal"; or

- to require the Non-electing Principal to purchase for cash all of the Electing Principal's Citrus stock.

In either case, the Citrus stock must be purchased or sold for a purchase price determined in accordance with the Capital Stock Agreement.

c. Northern Plains. CrossCountry will hold its interest in Northern Border Partners through Northern Plains. Northern Plains, directly and through its subsidiary, Pan Border, holds a general-partner interest of approximately 1.65%, and a limited-partner interest of approximately 1.06%, in Northern Border Partners.

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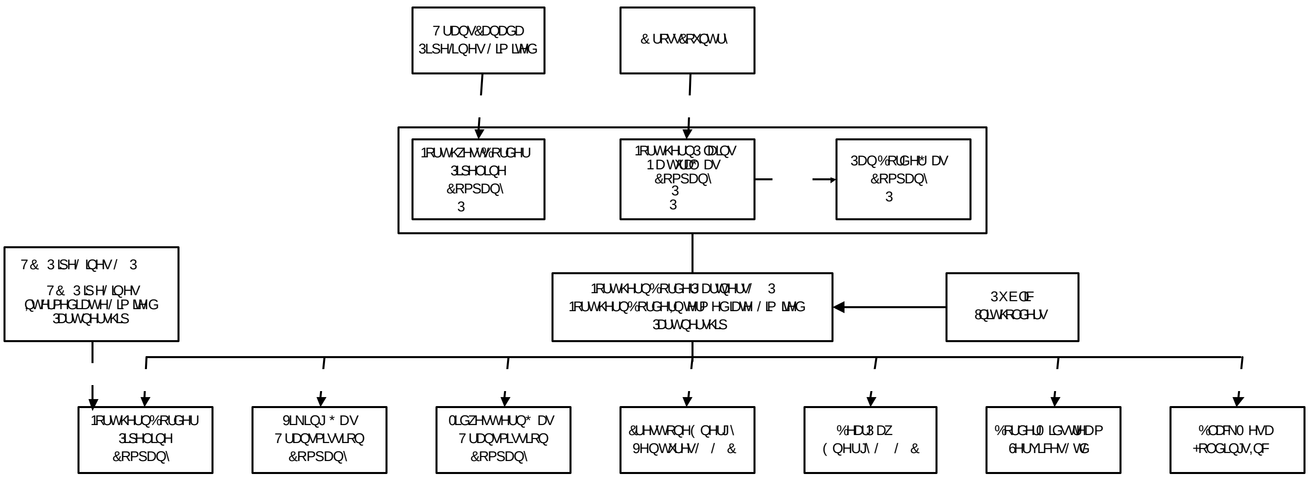

(1) TC PipeLines Intermediate Limited Partnership is a subsidiary of TC PipeLines, LP. TC PipeLines, LP is a publicly traded partnership whose general partner, TC PipeLines GP, Inc., is a wholly owned subsidiary of TransCanada PipeLines Limited.

In addition to the distributions received by Northern Plains on its limited-partner interests, Northern Plains also receives an incentive distribution from Northern Border Partners as a result of its ownership of general-partner interests in Northern Border Partners. Under the incentive distribution provisions of the Northern Border Partners partnership agreement, the general partners are entitled to incentive distributions if the amount distributed in any quarter exceeds $0.605 per common unit ($2.42 per common unit annualized). The general partners are entitled to 15% of amounts distributed in excess of $0.605 per common unit, 25% of amounts distributed in excess of $0.715 per common unit ($2.86 per common unit annualized), and 50% of amounts distributed in excess of $0.935 per common unit ($3.74 per common unit annualized). The amounts that trigger incentive distributions at various levels are subject to adjustment in certain events, as described in the Northern Border Partners partnership agreement. The actual level of distributions Northern Plains will receive in the future will vary with the level of distributable cash determined in accordance with the Northern Border Partners partnership agreement. The level of distributable cash that Northern Border Partners receives from Northern Border Pipeline, its largest subsidiary, is subject to a cash distribution policy that can only be modified by unanimous approval which includes entities not controlled by CrossCountry.

Northern Plains and Pan Border control 82.5% of the voting power on the Northern Border Partners partnership policy committee, which directs the activities of Northern Border Partners. The remaining 17.5% voting power on the Northern Border Partners partnership policy committee is held by Northwest Border Pipeline Company, a subsidiary of TransCanada PipeLines Limited. Pursuant to services and operating agreements, Northern Plains and NBP Services provide operating and administrative services to Northern Border Partners.

Northern Border Partners owns a 70% general partner interest in Northern Border Pipeline. The remaining 30% general partner interest in Northern Border Pipeline is owned by TC Pipelines Intermediate Limited Partnership, a subsidiary of TC Pipelines, LP, a publicly traded partnership. Northern Border Pipeline owns and manages a 1,249-mile natural gas pipeline system. The Northern Border Pipeline system consists of 822 miles of 42-inch diameter pipe from the Canadian border to Ventura, Iowa, capable of transporting a total of approximately 2.4 TBtu/d; 30-inch diameter pipe and 36-inch diameter pipe, each approximately 147 miles in length, capable of transporting approximately 1.5 TBtu/d in total from Ventura, Iowa to Harper, Iowa; 226 miles of 36-inch diameter pipe and 19 miles of 30-inch diameter pipe capable of transporting approximately 844 BBtu/d from Harper, Iowa to Manhattan, Illinois (Chicago area); and 35 miles of 30-inch diameter pipe capable of transporting approximately 545 BBtu/d from Manhattan, Illinois to a terminus near North Hayden, Indiana.

Along the Northern Border Pipeline system there are 16 compressor stations with a total of 499,000 hp and measurement facilities to support the receipt and delivery of gas at various points. Other facilities include four field offices and a microwave communication system with 51 tower sites. In the year ended December 31, 2002, Northern Border Partners estimated that Northern Border Pipeline transported approximately 20% of the total amount of natural gas imported from Canada to the United States.

The Northern Border Pipeline system serves more than 50 firm transportation shippers with diverse operating and financial profiles. Based upon shippers' contractual obligations, as of December 31, 2002, 91% of the firm capacity was contracted by producers and marketers. The remaining firm capacity was contracted to local distribution companies (6%), interstate pipelines (2%) and end-users (1%). As a result of commercial activity during July 2003, approximately 100% of Northern Border Pipeline's capacity is under contract through December 31, 2003 and, assuming no extensions of existing contracts or execution of new contracts, approximately 70% is under contract through December 31, 2004 and approximately 59% through December 31, 2005.

Midwestern, a subsidiary of Northern Border Partners, owns a 350-mile pipeline system extending from an interconnection with Tennessee Gas Transmission near Portland, Tennessee to a point of interconnection with several interstate pipeline systems near Joliet, Illinois. Midwestern's pipeline system serves markets in Chicago, Kentucky, southern Illinois, and Indiana. Midwestern's pipeline system consists of 350 miles of 30-inch diameter pipe with a capacity of approximately 650 BBtu/d for volumes transported from Portland, Tennessee to the north. There are seven compressor stations with a total of 69,070 hp.

Effective January 17, 2003, Northern Border Partners acquired Viking, including a one-third interest in Guardian Pipeline L.L.C., from Xcel Energy Inc. The Viking pipeline system extends from an interconnection with TransCanada near Emerson, Manitoba to an interconnection with ANR Pipeline Company near Marshfield, Wisconsin. Viking also has interconnections with NNG and Great Lakes Gas Transmission to serve markets in Minnesota, Wisconsin, and North Dakota. The Viking pipeline system consists of 499-miles of 24-inch diameter mainline pipeline with a design capacity of approximately 500 BBtu/d at the origin near Emerson, Manitoba and 300 BBtu/d at the terminus near Marshfield, Wisconsin, 95 miles of 24-inch mainline looping and 79 miles of smaller diameter lateral pipelines. There are eight compressor stations with a total of 68,650 hp. Based upon shipper contractual obligations as of December 31, 2002, approximately 72% of the firm transportation capacity is contracted by local distribution companies, 24% by marketers, and 4% by end-users. Viking's source of gas supply is the western Canadian sedimentary basin.

Through its ownership of Bear Paw Energy, LLC and Crestone Energy Ventures, Northern Border Partners has ownership interests in gathering systems in the Powder River, Wind River, and Williston basins and processing plants in the Wind River and Williston basins in the United States. Northern Border Partners also owns an interest in gathering pipelines in Alberta, Canada, through its subsidiary Border Midstream Services, Ltd. Northern Border Partners' subsidiary Black Mesa owns a 273-mile coal slurry pipeline and transports coal-water slurry via a pipeline in the southwestern United States. Northern Border Partners' gas gathering and processing segment provides services for the gathering, treating, processing and compression of natural gas and the fractionation of NGLs for third parties and related field services. Northern Border Partners does not explore for, or produce, crude oil or natural gas, and does not own crude oil or natural gas reserves. Refer to Section XIV.H.1.f., "Expansion of Northern Border Partners' Midstream Gas Gathering Business" for further information.

On October 24, 2003, Northern Border Partners announced that it recorded a non-cash charge in the third quarter 2003 of approximately $219 million to reflect asset and goodwill impairments for its natural gas gathering and processing business segment.

The impairment analyses were performed in accordance with Statement of Financial Accounting Standards (SFAS) No. 142, Goodwill and Other Intangibles and SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets. SFAS No. 142 applies to goodwill for consolidated subsidiaries and became effective January 1, 2002. Under the standard, companies no longer amortize goodwill but are required to perform annual assessments of whether the book value of the goodwill is impaired. As indicated in Northern Border Partners' second quarter 2003 10-Q, the annual SFAS No. 142 impairment test was accelerated from the fourth quarter to the third quarter due to lower throughput volumes experienced and anticipated in the Powder River gathering systems. Northern Border Partners also performed an analysis of the carrying value of all of the tangible assets in the natural gas gathering and processing business segment under SFAS No. 144. The impairment charges are comprised of approximately $76 million related to the tangible assets in the Powder River Basin and approximately $143 million for the goodwill related to Northern Border Partners' gas gathering and processing segment. (For further information, reference Northern Border Partners' report for third quarter 2003 on Form 10-Q, which is required to be filed by November 14, 2003.)

Additional information concerning the business of Northern Border Partners is contained in Northern Border Partners' 2002 annual report on Form 10-K, quarterly reports for the first, second and third quarters 2003 on Form 10-Q (Northern Border Partners' Form 10-Q for the third quarter of 2003 is required to be filed by November 14, 2003), and current reports on Form 8-K, which are available in the "Related Documents" section at http://www.enron.com/corp/por/. For financial information on Northern Border Partners, refer to the consolidated financial statements of Northern Border Partners and related Management's Discussion and Analysis of Financial Condition and Results of Operations included in Northern

Border Partners' annual report on Form 10-K. The Debtors did not prepare these reports, but they contain information which may be relevant to the Creditors' decision to approve the Plan.

3. Competition

The interstate Pipeline Businesses compete with other pipeline companies for transportation customers on the basis of transportation rates, access to competitively priced supplies of natural gas in markets served by the pipelines, and the quality and reliability of transportation services. The competitiveness of transportation services on a given pipeline to any market is generally determined by the total delivered natural gas price from a particular supply basin to the market served by the pipeline. The cost of transportation on the pipeline is only one component of the total delivered cost.

Overall, the interstate Pipeline Businesses' transportation volumes are also affected by factors such as the availability and economic attractiveness of other energy sources. Hydroelectric generation, for example, may become available based on ample snowfall and displace demand for natural gas as a fuel for electric generation. In providing interruptible and short-term transportation service, the interstate Pipeline Businesses also compete with released capacity offered by shippers holding firm contract capacity on their pipelines.

a. Transwestern. Transwestern competes with several interstate pipelines to serve the California market. These major competitors are Pacific Gas and Electric-Gas Transmission Northwest Corporation, Kern River, El Paso Natural Gas, and Southern Trails Pipeline Company. Pacific Gas and Electric-Gas Transmission Northwest Corporation transports western Canadian supplies and Kern River transports Rocky Mountain supplies to the California markets. Like Transwestern, El Paso Natural Gas transports southwest United States supplies from the San Juan, Permian, and Anadarko basins to the California border. Southern Trails Pipeline Company carries approximately 80 BBtu/d from the San Juan area to the California border. Transwestern's pipeline capacity currently represents approximately 15% of the available pipeline capacity to the California markets. Transwestern and El Paso Natural Gas are the only interstate pipelines that currently serve the Arizona and New Mexico markets.

Kern River has completed an expansion that increased its capacity capable of reaching the California border by approximately 900 BBtu/d. The Kern River expansion was placed in-service May 1, 2003. El Paso Natural Gas received FERC approval to complete its "Power Up" Project adding additional transportation capacity of 320 BBtu/d to the California border by April 1, 2005. When the primary term of Transwestern's firm contracts expire, competition from Kern River and El Paso Natural Gas may have a material adverse effect on Transwestern's ability to extend its contracts at maximum tariff rates. Refer to Section XIV.H.1.d., "Maintenance and Expiration of Transportation Service Agreements" for further information.

b. Citrus. Historically, the Florida Gas pipeline system has been the only interstate natural gas pipeline system serving peninsular Florida. This changed on May 28, 2002, when Phase I of the Gulfstream expansion was placed into service. Gulfstream is sponsored by a joint venture of Duke Energy Corporation and The Williams Companies. According to Gulfstream's press releases, Phase I of the Gulfstream project consists of a 581-mile pipeline system that originates near Pascagoula, Mississippi and Mobile, Alabama and traverses the Gulf of Mexico to Florida, coming onshore near Tampa in Manatee County, Florida. Gulfstream's filings with FERC report that Gulfstream has firm contracts for over approximately 300 BBtu/d on a pipeline with a certificated capacity of approximately 1 TBtu/d. CrossCountry understands that Gulfstream has direct connections with six of Florida Gas's customers.

Gulfstream has interconnects with Florida Gas's pipeline system in Hardee and Osceola Counties, Florida. Gulfstream has proposed a Phase II expansion across central Florida, which would ultimately extend its pipeline system to Palm Beach County. Gulfstream's Phase II expansion was originally scheduled to be placed into service on or about June 1, 2003, but Gulfstream has delayed the Phase II expansion in-service date.

In a May 30, 2003 press release, Gulfstream announced the execution of a 23-year firm transportation agreement with Florida Power & Light Company in which Gulfstream will provide up to 350 BBtu/d of firm gas transportation service for their planned Martin and Manatee repowering projects in mid-2005.

Gulfstream's primary future target markets are expected to be gas-fired electric generation projects that are anticipated to be developed over the next 10 years. Gulfstream's proposed tariff rates after the completion of its Phase II expansion are expected to be comparable to Florida Gas's incrementally priced firm transportation service rate schedule (FTS-2). Gulfstream may directly compete with Florida Gas to serve several customers. This would not affect the collection of the reservation revenues on Florida Gas's current contracts, but it could impact the usage of Florida Gas's facilities. CrossCountry believes that Florida Gas's contracts expiring prior to 2015 (FTS-1 contracts) will not be materially impacted by Gulfstream, as the reservation rates under these contracts are lower than Gulfstream's current tariff. However, when the primary terms of the first FTS-2 contracts expire in 2015, competition from Gulfstream may have a material adverse effect on Florida Gas's ability to extend such contracts at maximum tariff rates. Refer to Section XIV.H.1.d., "Maintenance and Expiration of Transportation Service Agreements" for further information.

Florida Gas also serves the Florida panhandle, where it competes with Gulf South Pipeline Company and the natural gas transportation business of the South Georgia system, which is owned by Southern Natural Gas. Florida Gas faces additional competition to a lesser degree, from alternate fuels, including residual fuel oil, in the Florida market, as well as from proposed LNG facilities.

c. Northern Plains. Northern Border Pipeline and Viking compete with other pipeline companies that transport natural gas from the western Canadian sedimentary basin or that transport natural gas to end-use markets in the midwest United States. Their competitive positions are affected by the availability of Canadian natural gas for export, the availability of other sources of natural gas and demand for natural gas in the United States. Demand for transportation services on these pipeline systems is affected by natural gas prices, the relationship between export capacity and production in the western Canadian sedimentary basin, and natural gas shipped from producing areas in the United States. Shippers of natural gas produced in the western Canadian sedimentary basin also have other options to transport Canadian natural gas to the United States, including transportation on the Alliance Pipeline and

TransCanada's pipeline system, through various interconnects with U.S. interstate pipelines or to markets on the west coast of the United States.

Midwestern can receive and deliver gas at either end of its pipeline system, which makes it a header pipeline system. Consequently, Midwestern faces competition from multiple supply sources and interstate pipelines. In the Chicago market, Midwestern competes with pipelines transporting gas from the Gulf Coast and the mid-continent and gas sourced from Canada. In the Indiana and Western Kentucky markets, Midwestern competes primarily against pipelines transporting gas from the Gulf Coast and mid-continent into these markets.

4. Demand for Natural Gas Pipeline Transportation Capacity

The long-term financial condition of the Pipeline Businesses is dependent on the continued availability of economic natural gas supplies. Natural gas reserves may require significant capital expenditures by others for exploration and development drilling and the installation of production, gathering, storage, transportation, and other facilities that permit natural gas to be produced and delivered to pipelines that interconnect with the Pipeline Businesses' pipeline systems. Low prices for natural gas, regulatory limitations or the lack of available capital for these projects could adversely affect the development of additional reserves and the production, gathering, storage, and pipeline transmission of natural gas supplies.

Each of the interstate Pipeline Businesses also depends on the level of demand for natural gas in the markets the interstate Pipeline Businesses serve. The volumes of natural gas delivered to these markets from other sources affect the demand for both the natural gas supplies and the use of the pipeline systems. Demand for natural gas to serve other markets also influences the ability and willingness of shippers to use the interstate Pipeline Businesses' systems to meet demand in the markets that the interstate Pipeline Businesses serve.

A variety of factors could affect the demand for natural gas pipeline capacity in the markets that the interstate Pipeline Businesses serve. These factors include:

- economic conditions;
- fuel conservation measures;
- alternative energy availability and prices;
- gas storage inventory levels;
- climatic conditions;
- government regulation; and
- technological advances in fuel economy and energy generation devices.

The interstate Pipeline Businesses' primary exposure to market risk occurs at the time existing transportation contracts expire and are subject to renegotiation. A key determinant of the value that customers can realize from firm transportation on a pipeline is the basis differential or market price spread between two points on the pipeline and/or competition from other pipelines or other fuels. The difference in natural gas prices between the points along the pipeline where gas enters and where gas is delivered represents the gross margin that a customer can expect to achieve from holding transportation capacity at any point in time. This margin and its variability become important factors in determining the rates customers are willing to pay when they renegotiate their transportation contracts. The basis differential between markets can be affected by trends in production, available capacity, storage inventories, weather, and general market demand in the respective areas.

CrossCountry cannot predict whether these or other factors will have an adverse effect on demand for use of the interstate Pipeline Businesses to be contributed to CrossCountry or how significant that adverse effect could be. Refer to Section XIV.H.1.i., "Significant Decrease in Demand for Natural Gas" for further information.

5. Seasonality

Transwestern's demand is not distinguished by strong seasonal patterns. Demand for delivery capacity to the western market is impacted by natural gas requirements for electric generation in the Southwest region, which can be significantly impacted by high/low hydro-electric power generation levels available from the Pacific Northwest. Management of storage fields in California allow utilities to levelize peak demand for natural gas. Demand for delivery capacity to the eastern market can be impacted by electric generation gas requirements in the Texas intrastate markets for summer air conditioning loads and by demand for winter heating gas requirements in the Midwestern markets. With minor exceptions, Transwestern's long-term transportation agreements are not subject to seasonal fluctuations in demand revenues.

Florida Gas has experienced significant fluctuation in seasonal demand for natural gas transportation into Florida, with historically the highest throughput occurring from May through September. Florida Gas's contracted for base capacity peaks in the summer to coincide with the electric load needed to provide air conditioning in the Florida market. In spite of seasonal fluctuations, Florida Gas's pipeline system has consistently exceeded an annual pipeline throughput load factor of over 85%. However, because of the straight-fixed variable (SFV) rate design implemented in 1993, these seasonal fluctuations have not had a material impact on Florida Gas's revenues or net income. For the last several years, the higher cost of competing fuel to Florida Gas's customers has created additional demand for natural gas, and the pipeline throughput has remained at high levels effectively year round; however, price differentials between competing fuels and natural gas fluctuate on a periodic basis. CrossCountry cannot predict whether or to what extent these conditions will continue.

Throughput on Northern Border Partners' pipelines may experience seasonal fluctuations depending upon the level of winter heating load demand or summer electric generation usage in the markets served by the pipeline systems. However, since approximately 98% of the agreed upon cost of service for these pipelines is attributable to demand charges, Northern Border Partners' revenues are not impacted materially by such seasonal throughput variations.

6. Regulatory Environment

The interstate Pipeline Businesses to be contributed to CrossCountry pursuant to the formation transactions are regulated by FERC under the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. Generally, FERC's authority extends to:

- transportation of natural gas;
- rates and charges;
- certification and construction or acquisition of facilities;
- abandonment of facilities;
- initiation and discontinuation of service;
- maintenance of accounts and records;
- relationships between pipelines and their marketing affiliates;
- terms and conditions of service; and
- depreciation and amortization policies.

FERC regulates the rates and charges for transportation in interstate commerce. Natural gas companies may not charge rates exceeding rates determined to be just and reasonable by FERC. Generally, rates for interstate pipelines are based on the applicable pipeline's cost of service, including recovery of, and a return on, the pipeline's actual historical net investment. In addition, FERC prohibits natural gas companies from unduly preferential or discriminatory treatment of any person with respect to pipeline rates or terms and conditions of service. Some types of rates may be discounted without further FERC authorization and rates may be negotiated subject to FERC approval. The rates and terms and conditions for service are found in FERC approved tariffs. Under its tariff, an interstate pipeline is allowed to charge for its services on the basis of stated transportation rates. Transportation rates are established periodically in FERC proceedings known as rate cases. The tariff also allows the interstate pipeline to provide services under negotiated and discounted rates.

The fees or rates established under the interstate Pipeline Businesses' tariffs are a function of their costs of providing services to their customers, including a reasonable return on invested capital; consequently, their financial results have historically been relatively stable. However, these results can be subject to volatility due to factors such as weather, changes in natural gas prices and market conditions, regulatory actions, competition, and the creditworthiness of customers. From time to time, the interstate Pipeline Businesses file to make changes to their tariffs to clarify provisions, to reflect current industry practices and to reflect recent FERC changes in regulations and other rulings. Refer to Section XIV.H.1.c., "FERC Imposed Tariff Adjustments" for further information.

FERC Order No. 636 required interstate natural gas pipelines that perform open access transportation under blanket certificates to "unbundle" or separate their traditional merchant sales services from their transportation and storage services. In addition Order No. 636

required pipelines to provide comparable transportation and storage services with respect to all natural gas supplies, whether such natural gas is purchased from the pipeline or from other merchants such as marketers or producers. Each interstate natural gas pipeline is required to separately state the applicable rates for each unbundled service. Except for certain marketing subsidiaries, the Pipeline Businesses proposed to be contributed to CrossCountry pursuant to the formation transactions do not provide merchant services, except for Transwestern, which provides sales service to certain small customers.

On February 9, 2000, FERC issued Order No. 637, which amended specified regulations governing interstate natural gas transmission companies in response to the development of more competitive markets for natural gas and the transportation of natural gas. Among other things, FERC Order No. 637 revised FERC pricing policy by waiving price ceilings for short-term released interstate pipeline transportation capacity for a two-year period (which expired on September 30, 2002), and effected changes in FERC regulations relating to interstate transportation scheduling procedures, capacity segmentation, pipeline penalties, rights of first refusal and information reporting. Most major aspects of Order No. 637 are pending judicial review. It is uncertain whether and to what extent FERC's market reforms will survive judicial review and, if so, whether FERC's actions will achieve the goal of further increasing competition in natural gas markets. The final rule also required the posting of corporate and pipeline organizational charts, names, and job descriptions. The reporting requirements became effective September 1, 2000.

The interstate Pipeline Businesses are also subject to the requirements of FERC Order Nos. 497 and 566, which prohibit preferential treatment by an interstate natural gas pipeline of its marketing affiliates and govern the information an interstate natural gas pipeline can provide to its marketing affiliates. On September 27, 2001, FERC issued a NOPR in Docket No. RM01-10 in which it proposed new standards of conduct that would apply uniformly to natural gas pipelines and public utilities transmitting electricity. FERC is proposing one set of standards to govern relationships between such regulated natural gas and electric transmission providers and all energy affiliates. Should a final rule be issued in this proceeding, the interstate Pipeline Businesses to be contributed to CrossCountry pursuant to the formation transactions may be subject to standards that could result in additional costs and separation of functions and staffing with its affiliates. In May 2002, FERC held a technical conference on the proposed rulemaking. To date, FERC has not acted on the proposal.

On July 17, 2002, FERC issued a Notice of Inquiry Concerning Natural Gas Pipeline Negotiated Rate Policies and Practices in Docket No. PL02-6-000. Subsequently, FERC issued an order on July 25, 2003, modifying its prior policy on negotiated rates. FERC ruled that it would no longer permit the pricing of negotiated rates based upon natural gas commodity price indices. Negotiated rates based upon such indices may continue until the end of the contract period for which such rates were negotiated, but such rates will not be prospectively approved by FERC. FERC also imposed certain requirements on other types of negotiated rate transactions to ensure that the agreements embodying such transactions do not materially differ from the terms and conditions set forth in the tariff of the pipeline entering into the transaction. Since the Pipeline Businesses do not derive a significant source of their revenues from negotiated rate transactions, this FERC ruling is not expected to have a material effect on their businesses.

Recent FERC orders in proceedings involving other natural gas pipelines have addressed certain aspects of the pipelines' creditworthiness provisions set forth in their tariffs. In addition, industry groups such as the Northern American Energy Standards Board are studying creditworthiness standards and may recommend that FERC promulgate changes in such standards on an industry-wide basis. The enactment of some of these recommendations may have the effect of easing certain creditworthiness standards and parameters currently reflected in the interstate Pipeline Businesses' tariffs. Recent FERC orders have indicated, however, that pipelines are free to negotiate credit terms relative to the construction of new facilities by a pipeline, which are then effective for the term of the contract and are not superceded by tariff provisions once the facilities are completed. At this stage of the rulemaking proceedings, however, CrossCountry cannot predict what changes may be required, if any, or the ultimate impact, if any, such changes would have on the Pipeline Businesses.

On August 1, 2002, FERC issued a NOPR in Docket No. RM02-14-000 regarding the regulation of the cash management practices of the natural gas and other companies that it regulates. On June 26, 2003, FERC issued an interim rule in that proceeding that amended FERC's regulations to provide for documentation requirements for cash management programs and to implement new reporting requirements. Specifically, under the interim rule, all cash management agreements between regulated entities and their affiliates must be in writing, must specify the duties and responsibilities of cash management participants and administrators, must specify the methods for calculating interest and for allocating interest income and expense, and must specify any restrictions on deposits or borrowings by participants. A FERC-regulated entity must file with FERC any cash management agreements to which it is a party, as well as any subsequent changes to such agreements. In addition, a FERC-regulated entity must notify FERC when its proprietary capital ratio falls below 30%. Such notification must include the entity's proprietary capital ratio, the significant event(s) or transaction(s) that contributed to the proprietary capital ratio falling below 30%, the extent to which the entity has amounts loaned or advanced to others within its corporate group through its cash management program, and plans, if any, to raise its proprietary capital ratio. The entity is also required to notify FERC when the entity's proprietary capital ratio subsequently returns to or exceeds 30%. This FERC ruling is not expected to have a material effect on CrossCountry.

Also on August 1, 2002, FERC's Chief Accountant issued an Accounting Release providing guidance on how companies should account for money pool arrangements and the types of documentation that should be maintained for these arrangements. However, the Accounting Release did not address the proposed requirement that a FERC-regulated entity maintain a minimum proprietary capital balance of 30% and that the entity and its parent have investment-grade credit ratings. Requests for rehearing were filed on August 30, 2002. FERC has not yet acted on the rehearing requests. Although it cannot predict the outcome of the rehearing, CrossCountry does not expect that FERC's proposed accounting rules/guidance will have a material adverse impact on the interstate Pipeline Businesses' cash management practices.

The Pipeline Safety Improvement Act of 2002, Public Law 107-355, was signed into law on December 17, 2002, providing guidelines in the areas of risk analysis and integrity management, public education programs, verification of operator qualification programs and filings with the National Pipeline Mapping System. The Pipeline Safety Improvement Act of 2002 requires pipeline companies to perform integrity assessments on pipeline segments that exist in high population density areas or near specifically identified sites that are designated as high consequence areas. Pipeline companies are required to perform the integrity assessments within ten years of the date of enactment and must perform subsequent integrity assessments on a seven-year cycle. At least 50% of the highest risk segments must be assessed within five years of the enactment date. The risk ratings are based on numerous factors, including the population density in the geographic regions traversed by a particular pipeline, as well as other factors related to the condition of the pipeline and its protective coating and the pipeline segment's susceptibility or vulnerability to various other integrity threats, such as third-party damage. Assessments will consist of hydrostatic testing, internal electronic testing, or direct assessment of the piping. In addition, within one year of the law's enactment, the Pipeline Businesses' operator qualification programs, in force since the mandatory compliance date of October 2002, must also conform to standards the DOT is responsible for providing. The regulations implementing the Pipeline Safety Improvement Act of 2002 are not yet final. Rules on integrity management, direct assessment usage, and the operator qualification standards are mandated by the Pipeline Safety Improvement Act of 2002 to be completed by December 17, 2003. CrossCountry cannot predict the outcome or impact of these rules and regulations. The interstate Pipeline Businesses have made the required filings with the national Pipeline Mapping System, and have reviewed and revised their Public Education Program, both as required by the Pipeline Safety Improvement Act of 2002.

Additional proposals that might affect the natural gas pipeline industry are considered from time to time by Congress, FERC, the DOT, other Federal agencies, state regulatory bodies, and the courts. CrossCountry cannot predict when or if any new proposals might be implemented or, if so, how CrossCountry's Pipeline Businesses might be impacted.

CrossCountry is a subsidiary of ENE, currently an exempt holding company under PUHCA. In a proceeding regarding the status of ENE's exemption, an SEC Administrative Law Judge issued an initial decision on February 6, 2003, denying ENE's exemption, and ENE subsequently petitioned the SEC for review of that decision. The SEC granted ENE's petition and briefing has been completed. ENE continues to be exempt pending the SEC's final order. If ENE cannot maintain an exemption under PUHCA and it must register as a holding company, ENE and its subsidiaries, including CrossCountry, may become subject to additional regulation by the SEC under PUHCA with respect to certain matters, including transactions with ENE and its subsidiaries. Refer to Section XIV.E.2., "PUHCA" for further information.

a. Transwestern. In January 2002, FERC initiated an audit of Transwestern's compliance with FERC's accounting and reporting requirements and regulations, including requirements and regulations relating to cash management practices. On September 8, 2003, FERC issued an order finding that the audit did not identify any instances of non-compliance with such requirements and regulations.

On July 27, 1995 and on October 16, 1996, respectively, FERC approved Transwestern's 1995 Global Settlement and 1996 Mini-Settlement (Docket Nos. RP95-271, et al.) resolving all issues related to Southern California Gas's turnback of capacity, all outstanding issues in the Transwestern's Order 636 restructuring proceeding, its pending certificate proceedings relating to the abandonment of gathering facilities and other rate proceedings. The

Global and Mini-Settlements established rates applicable to seven shippers (or their successors) specified as Current Firm Customers in Transwestern's tariff. The rates applicable to the Current Firm Customers were originally lower than the maximum tariff rates applicable to other customers, but escalate each year based on inflation, with a minimum annual increase of 2% and a maximum annual increase of 5%. The Global Settlement also provided that, effective November 1, 2001, Transwestern would be at risk for recovery of all costs assigned to unsubscribed capacity.

Transwestern has completed its transition under Order No. 636, unbundling its transportation services and eliminating its sales service obligation as required by Order 636. Transwestern's tariff formula was designed to recover a cost of service that would reflect an 11.50% return on equity with a pre-tax return of 14.65%. These returns were part of Transwestern's 1994 rate case settlement.

In Order No. 637, FERC made changes to its current regulatory model to enhance the effectiveness and efficiency of gas markets as they have evolved since Order No. 636. On August 17, 2000, and again on December 21, 2002, Transwestern filed changes to its tariff to comply with Order No. 637. In an order issued October 10, 2002, FERC found that Transwestern had generally complied with Order No. 637 and required Transwestern to file tariff sheets in compliance with the October 10, 2002 Order. On November 12, 2002, Transwestern made its filing in compliance with the October 10, 2002 Order. The compliance filing was accepted by a FERC order issued on December 30, 2002 with tariff sheets effective January 1, 2003.

In February 2001, Transwestern filed negotiated rate transactions in Docket Nos. RP97-288-009, 010, 011 and 012 with Sempra Energy Trading and Richardson Products Company containing index based rates. On March 2, 2001, FERC issued an order accepting Transwestern's negotiated rates transactions in the above-referenced proceedings, subject to refund and subject to a further FERC order on the merits. On July 26, 2001, FERC issued an order setting these proceedings for an expedited hearing, which was held on August 29, 2001. Based on the testimony and other evidence presented at the hearing, the presiding administrative law judge issued findings of fact and law favorable to Transwestern. Subsequent to the filing of these negotiated rate transactions, Transwestern filed additional negotiated rate transactions in other dockets. FERC also accepted those transactions, subject to refund and subject to the outcome of the proceedings in Docket Nos. RP97-288-009, 010, 011 and 012. On July 17, 2002, FERC issued an order that rejected the findings of the administrative law judge and that required Transwestern to refund the amounts by which the negotiated rate transactions with Sempra Energy Trading and Richardson Products Company exceeded Transwestern's applicable maximum tariff rates. In the order, FERC states that Transwestern violated the terms of its FERC gas tariff and its website. The focus of the order was Transwestern's pricing of transportation service based on differentials in commodity price indices. FERC precluded Transwestern from entering into new contracts priced on that basis for a one-year period, which expired July 17, 2003. Transwestern subsequently negotiated with its customers a settlement of all pending negotiated rate proceedings with the exception of the rate proceedings in connection with the Red Rock expansion project. This settlement has been approved by FERC and Transwestern made the refunds of approximately $9.9 million (including interest of $1.1 million), required by the settlement on March 14, 2003.

The Red Rock expansion contracts provide for a one part fixed demand rate that is not tied to differentials in commodity price indices. Although the Red Rock expansion contracts do not involve index-based pricing, they do provide for pricing in excess of Transwestern's maximum rates. If FERC changes its current policy permitting such pricing, Transwestern may be required to modify the rates payable under those agreements and make refunds of amounts already collected in excess of maximum tariff rates.

On March 29, 2001, Transwestern filed with FERC a Section 7(b)/7(c) application for Transwestern's Red Rock expansion requesting permission and approval to: (1) abandon in-place existing units totaling 49,500 hp at Transwestern's pipeline Stations 1, 2, 3, and 4, and (2) install a 41,500 hp unit at each station, resulting in approximately 150,000 MMBtu/d of incremental firm capacity from Thoreau, New Mexico to the California border. Transwestern received a FERC order dated July 16, 2001 approving its application request, and commenced construction on December 26, 2001. On November 26, 2001, Transwestern filed a request with FERC to extend the construction completion date for Station 4 to July 16, 2003. Transwestern does not anticipate that it will place Station 4 in-service under this authorization. The Red Rock expansion was placed in-service on June 15, 2002.

On August 1, 2002, FERC issued an Order to Respond in Docket No. IN02-6-000. The August 1, 2002 Order required Transwestern to provide, within 30 days of the date of the August 1, 2002 Order, written responses stating why FERC should not find that Transwestern: (1) violated FERC's Uniform System of Accounts by failing to maintain written cash management agreements with their parent company; (2) acted imprudently in entering into certain secured loan arrangements; and (3) should be prohibited from passing costs arising from such loans and arrangements on to ratepayers in future rate proceedings before FERC. On September 3, 2002, Transwestern filed a written response with FERC. On October 31, 2002, FERC issued an Order Approving Stipulation and Consent Agreement approving a Stipulation and Consent Agreement between FERC's Chief Accountant, Division of Enforcement and Investigations, Office of Market Oversight and Investigations, and Transwestern. The stipulation provides, among other things, that: (a) Transwestern will comply with the final rule regarding written cash management practices resulting from FERC's NOPR, Regulation of Cash Management Practices, in Docket No. RM02-14-000 issued August 1, 2002; (b) Transwestern will not include the costs associated with the $550 million loan entered into by Transwestern on November 13, 2001 in any future rate proceedings before FERC; and (c) FERC reserves the right to determine, in any future proceeding under Section 4 of the Natural Gas Act, whether the costs associated with any future refinancing of the $550 million loan entered into by Transwestern on November 13, 2001 are just and reasonable.

On November 21, 2002, the "Indicated Shippers" filed a request for clarification and/or rehearing of the October 31, 2002 Order. The Indicated Shippers contend that language in the October 31, 2002 Order is inconsistent with the terms of the stipulation. Specifically, the Indicated Shippers argue that certain language in the October 31, 2002 Order would preclude Transwestern from passing through to its rate payers the costs of any refinancing or replacement of the original $550 million loan, while the stipulation itself contains no such prohibition. On December 2, 2002, Transwestern filed a response to the Indicated Shippers' pleading, which sets forth Transwestern's arguments that there is no such inconsistency, and, alternatively, if such an inconsistency does exist, it must be resolved in favor of the language in the stipulation. FERC has not yet acted on either the Indicated Shippers' request for clarification and/or rehearing or Transwestern's response to such request.

Transwestern has entered into compression services agreements with ECS, a non-Debtor ENE affiliate, and continues to perform under the terms of such agreements. The agreements require ECS to provide electric horsepower capacity and related horsepower hours to be used to operate the Bisti, Bloomfield, and Gallup electric compressor stations located in New Mexico for which Transwestern pays ECS a compression service charge in cash and in volumes of natural gas. In addition, ECS is required to pay Transwestern a monthly operating and maintenance fee to operate and maintain certain equipment owned by ECS at the facilities. On March 26, 2003, FERC issued a show cause order to ECS that required ECS to demonstrate why it did not violate the terms of its blanket natural gas marketing authorization from FERC when ECS allegedly engaged in certain transactions on the EnronOnline® electronic trading platform. On June 25, 2003, FERC issued an order that revoked ECS's blanket authorization. However, this order also provided ECS limited authorization for the sole use of marketing gas entitlements accrued under ECS's existing compression services agreements, which include the agreements ECS has entered into with Transwestern.

Under the terms of Transwestern's 1995 Global Settlement and 1996 Mini-Settlement discussed above, Transwestern is required to file a rate case with FERC to become effective no later than November 2006. Refer to Section XIV.H.1.c., "FERC Imposed Tariff Adjustments" for further information about the risks inherent in FERC rate reviews.

b. Citrus. In a series of orders issued in 1993, FERC approved Florida Gas's FERC Gas Tariff, Third Revised Volume No. 1, pursuant to which Florida Gas implemented the provisions of FERC Order No. 636 on November 1, 1993. The Order No. 636 tariff provided for unbundled firm and interruptible transportation services in Florida Gas's Western Division (Texas, Louisiana, Mississippi and Alabama) and Florida Gas's Market Area (Florida) and implemented the SFV rate design required by Order 636.

Florida Gas is currently subject to an audit by FERC of Florida Gas's compliance with FERC's accounting and reporting requirements and regulations, including, without limitation, requirements and regulations relating to cash management practices. FERC has submitted numerous data requests as part of that audit, and Florida Gas has responded to each of those data requests. It is currently not known whether the audit has been completed or what further information, if any, may be requested in connection with such audit or what the ultimate conclusions or results of such audit will be.

On March 1, 1995, Florida Gas placed into service its Phase III Expansion, which increased Florida Gas's market area capacity by approximately 530 BBtu/d to a total of approximately 1.4 TBtu/d. Because the cost of the much needed expansion, if rolled into existing rates, would have resulted in a rate increase to existing customers disproportionate to benefits they received, firm market area transportation service through the additional capacity is provided pursuant to an incrementally priced rate schedule, FTS-2. Florida Gas maintains separate accounting records and establishes separate maximum tariff rates for service through the capacity existing prior to the Phase III Expansion and for service through the capacity created by the Phase III Expansion and subsequent expansions.

Florida Gas currently offers firm and interruptible transportation service in its Western Division under Rate Schedules FTS-WD and ITS-WD, respectively. Florida Gas offers firm transportation service into its Market Area under Existing System Rate Schedules SFTS (for certain small customers) and FTS-1, and under Incremental System Rate Schedule FTS-2. In addition, Florida Gas offers market area interruptible transportation under Rate Schedule ITS-1. Florida Gas also offers a system-wide balancing service, when operating conditions permit, under Rate Schedule PNR.

Florida Gas's currently effective maximum tariff rates were established pursuant to the settlement of Florida Gas's Natural Gas Act Section 4 rate case filed in Docket No. RP96-366. Customers receiving service under Rate Schedule FTS-2, however, are being charged rates that currently are less than the maximum tariff rates applicable to Rate Schedule FTS-2 as a result of a discount agreed to in the settlement reached in Florida Gas's Phase IV Expansion proceeding and provisions in FERC orders in subsequent expansion proceedings. Pursuant to the rate case settlement and the Phase IV Settlement, Florida Gas filed a Natural Gas Act Section 4 rate case on October 1, 2003. Refer to Section XIV.H.1.c., "FERC Imposed Tariff Adjustments" for further information about the risks inherent in FERC rate reviews.

On December 1, 1998, Florida Gas filed a Natural Gas Act Section 7 certificate application with FERC in Docket No. CP99-94-000 to construct 205 miles of pipeline in order to extend the pipeline to Ft. Myers, Florida and to expand capacity by approximately 272,000 MMBtu/d (Phase IV Expansion). Expansion costs were estimated at $351 million. Florida Gas requested that expansion costs be rolled into the rates applicable to FTS-2 (Incremental Expansion) service. On June 2, 1999, Florida Gas filed a Stipulation and Agreement (Phase IV Settlement) which resolved all non-environmental issues raised in the certificate proceeding and modified the Rate Case Settlement to provide that Florida Gas could not file a general rate case to increase its base tariff rates prior to October 1, 2001 (except in certain limited circumstances), but was required to file a general rate case no later than October 1, 2003. The Phase IV Settlement was approved by FERC by order issued July 30, 1999, and became effective thirty days after the date that Florida Gas accepted an order issued by FERC approving the Phase IV Expansion project.

On August 23, 1999, Florida Gas amended its application on file with FERC to eliminate a portion of the proposed facilities (that would be delayed until the Phase V Expansion). The amended application reflected the construction of 139.5 miles of pipeline and an expansion of capacity in order to provide incremental firm service of approximately 196,405 MMBtu on an average annual day, with estimated project costs of $262 million. The Phase IV Expansion was approved by a FERC order issued February 28, 2000, and accepted by Florida Gas on March 29, 2000. The Phase IV Expansion was placed in service on May 1, 2001. Total costs through December 31, 2002 were $244 million.

On December 1, 1999 Florida Gas filed a Natural Gas Act Section 7 certificate application with FERC in Docket No. CP00-40-000 to construct 215 miles of pipeline and 90,000 hp of compression and to acquire an undivided interest in the existing Mobile Bay Lateral owned by Koch Gateway Pipeline Company (now Gulf South Pipeline Company, LP), in order to expand the system capacity to provide incremental firm service to several new and existing customers of approximately 270,000 MMBtu on an average annual day (Phase V Expansion).

Expansion and acquisition costs were estimated at $437 million. Florida Gas requested that expansion costs be rolled into the rates applicable to FTS-2 (Incremental Expansion) service. On August 1, 2000 and September 29, 2000, Florida Gas amended its application on file with FERC to reflect the withdrawal of two customers, the addition of a new customer and to modify the facilities to be constructed. The amended application reflected the construction of 167 miles of pipeline and 133,000 hp of compression to create additional capacity to provide approximately 306 MMBtu/d of incremental firm service. The estimated cost of the revised project was $462 million. The Phase V Expansion was approved by FERC order issued July 27, 2001, and accepted by Florida Gas on August 7, 2001. Portions of the project were placed in service from December 2001 through December 2002, with the remainder of the Phase V Expansion placed in service in April 2003. Total estimated costs for the project are $425 million.

On November 15, 2001, Florida Gas filed a Natural Gas Act Section 7 certificate application with FERC in Docket No. CP02-27-000 to construct 33 miles of pipeline and 18,600 hp of compression in order to expand the system to provide incremental firm service to several new and existing customers of approximately 85,000 MMBtu on an average annual day. Expansion costs are estimated at $100 million. Florida Gas requested the expansion costs be rolled into rates applicable to FTS-2 service. The application was approved by FERC order issued on June 13, 2002, and accepted by Florida Gas on July 19, 2002. Clarification was granted and a rehearing request of a landowner was denied by FERC Order of September 3, 2002. Construction is underway, and the first phase of the Phase VI Expansion was placed in-service on June 1, 2003. Except for certain compression modifications, the remainder of the Phase VI Expansion was placed in service on November 1, 2003.

By order on rehearing issued February 26, 2003, in Florida Gas's Order No. 637 compliance, FERC determined that Florida Gas was required to revise its tariff to afford within-the-path alternate nominations (which provide shippers the option to ship their gas to a more distant point at no incremental charge) a higher scheduling priority, but allowed Florida Gas to delay such filing until it filed its Natural Gas Act Section 4 Rate Case, which was filed on October 1, 2003. The February 26 Order also required Florida Gas to file tariff revisions within fifteen days to permit shippers to release capacity outside of the shippers' primary capacity paths.

On March 6, 2003, Florida Gas filed a motion for extension of time requesting that Florida Gas be allowed to delay the tariff filing until its next Natural Gas Act Section 4 rate case so that these changes, as well as the within-the-path scheduling priorities, could be considered in the overall context of cost allocation and rate design. FERC granted the request on March 18, 2003. Rehearing of the February 26 Order was sought on one issue and is pending. Florida Gas and several customers have filed petitions with the D.C. Circuit Court for review of these Order No. 637 compliance orders, docketed as City of Tallahassee, et al. v. FERC, No. 03-1116, et al. In addition, clarification of such order was also requested by a Florida Gas customer, and such request is pending.

On March 26, 2003, FERC issued an order in Docket No. RP03-311, requiring Citrus Trading to show cause as to why its blanket sales certificate should not be revoked, referring vaguely to price manipulation allegations (relating to 2000-2001 California market transactions and certain trading activities on July 19, 2001 that occurred on EnronOnline®, as contained in a FERC staff report that does not mention Citrus Trading). Citrus Trading filed its response on April 16, 2003, and, among other things, argued that the FERC order violated due process, because no specific allegations were made against Citrus Trading, and since Citrus Trading had never sold gas into the California market nor had it ever made trades on EnronOnline®. Citrus Trading requested that it be dismissed from the show cause proceeding and by order issued June 25, 2003, FERC dismissed Citrus Trading from the proceeding, taking no action against it.

On October 1, 2003, Florida Gas filed a general rate case, Docket No. RP04-12, proposing rate increases for all services, based upon a cost of service of approximately $167 million for the pre-expansion system and approximately $342 million for the incremental system. Based on test period reservation and usage determinants, the proposed rate increase under all Rate Schedules, ignoring the impact of existing rate caps, negotiated rates, and discounts, would generate approximately $56 million in additional annual transportation revenues for Florida Gas. The overall return requested is 11.81%, reflecting an 8.64% cost of debt and a 14.50% return on common equity, and is based on a capital structure of 45.92% debt and 54.08% equity. The cost of service for the pre-expansion system includes an increase in the depreciation rate applicable to onshore facilities, from 2.13% to 3.00%. Further, Florida Gas has proposed certain revisions to various rate schedules (to set a minimum level of No Notice ("NNTS") service and to limit the rights of small firm shippers (with straight-fixed tariff service "SFTS") to convert from FTS-1 service back to SFTS). Florida Gas also requested waiver of the required refunctionalization (from transmission to gathering) of its interest in the Matagorda Offshore Pipeline System facilities, as the costs involved would be minor, and for which a separate gathering rate would be administratively unjustified. In addition, Florida Gas proposed to include the un-reimbursed costs of the Western Division Expansion in its rate base (for which costs Florida Gas was to be reimbursed by its affiliate, ENA). Other prospective changes proposed by Florida Gas include (a) the change to a traditional cost-of-service (with straight-line depreciation) for the expansion system, (b) a proposed capital expenditure tracker which would allow recovery of and on certain future capital expenditures through rates, and (c) compliance with Order No. 637 regarding capacity priority and segmentation. Protests were due October 14, 2003, and a number were filed on many aspects of the case. Some protesting parties requested summary rejection/modification or expedited consideration of certain of these issues, including Florida Gas's requests for the capital expenditure tracker and proposed rate schedule revisions.

By order issued October 31, 2003, FERC accepted and suspended the effectiveness of Florida Gas's proposed rates for the statutory period of five months, which will allow Florida Gas to place the rates into effect subject to refund on April 1, 2004. Also, FERC rejected the proposed capital expenditure tracker, except in the case of security costs and required Florida Gas to file revised tariff sheets providing that in the case of force majeure events, Florida Gas will be required to refund only the return earned on the rate base and tax components of the reservation charge while for other events (such as an outage that does not qualify as a force majeure event) Florida Gas would be required to refund the full amount. In addition, FERC stated that it was re-docketing the Order No. 637 compliance tariff sheets from Florida Gas's rate case to the Order No. 637 proceeding. Florida Gas is considering whether to file for rehearing of the order or whether to seek consolidation of the rate case with the Order No. 637 compliance proceeding. There can be no assurance as to what rates FERC will ultimately approve. Finally, FERC stated that it will hold a technical conference with regard to the NNTS and SFTS issues, with FERC staff required to submit a report on the proposed changes within 120 days (prior to the end of the suspension period).

c. Northern Plains. Approximately 98% of the agreed upon cost of service for Northern Border Partners' interstate pipelines is attributed to demand charges. The remaining 2% is attributed to commodity charges based on the volumes of gas actually transported. Under the terms of settlement in Northern Border Pipeline's 1999 rate case, neither Northern Border Pipeline nor its existing shippers can seek rate changes until November 1, 2005, at which time Northern Border Pipeline must file a new rate case. Midwestern and Viking are under no obligation to file new rate cases, but may do so at their discretion if they decide to seek a rate increase. Prior to a future rate case, Northern Border Partners' pipelines will not be permitted to increase rates if costs increase, nor will they be required to reduce rates based on cost savings. As a result, these businesses' earnings and cash flow will depend on future costs, contracted capacity, the volumes of gas transported, and their ability to recontract capacity at acceptable rates.

Until new transportation rates are approved by FERC, Northern Border Partners' pipelines continue to depreciate their transmission plants at FERC-approved depreciation rates. For Northern Border Partners' pipelines, the annual depreciation rates on transmission plants in service are 2.25% for Northern Border Pipeline, 1.9% for Midwestern, and 2.0% for Viking. In order to avoid a decline in the transportation rates established in future rate cases as a result of accumulated depreciation, the interstate pipeline must maintain or increase its rate base by acquiring or constructing assets that replace or add to existing pipeline facilities or by adding new facilities.

In Northern Border Pipeline's 1995 rate case, FERC addressed the issue of whether the federal income tax allowance included in Northern Border Pipeline's proposed cost of service was reasonable in light of previous FERC rulings. In those rulings, FERC held that an interstate pipeline is not entitled to a tax allowance for income attributable to limited partnership interests held by individuals. The settlement of Northern Border Pipeline's 1995 rate case provided that, until at least December 2005, Northern Border Pipeline could continue to calculate the allowance for income taxes in the manner it had historically used. In addition, a settlement adjustment mechanism was implemented, which effectively reduces the return on rate base. These provisions of the 1995 rate case were maintained in the settlement of Northern Border Pipeline's 1999 rate case.

Northern Border Partners' pipelines also provide interruptible transportation service. The maximum rate that may be charged to interruptible shippers is calculated as the sum of the firm transportation maximum reservation charge and commodity rate. Under its tariff, Northern Border Pipeline shares net interruptible transportation service revenue and any new services revenue on an equal basis with its firm shippers through October 31, 2003. However, Northern Border Pipeline is permitted to retain revenue from interruptible transportation service to offset any decontracted firm capacity. Neither Midwestern nor Viking share revenue from interruptible transportation service with firm shippers.

From time to time, Northern Border Partners' pipelines file to make changes to their respective tariffs to clarify provisions, to reflect current industry practices, and to reflect recent FERC rulings. In February 2003, Northern Border Pipeline filed to amend the definition of company use gas, which is gas supplied by its shippers for its operations, to clarify the language by adding detail to the broad categories that comprise company use gas. Relying upon the currently effective version of the tariff, Northern Border Pipeline included in its collection of company use gas quantities that were equivalent to the cost of electric power at its electric-driven compressor stations during the period of June 2001 through January 2003. On March 27, 2003, FERC issued an order rejecting Northern Border Pipeline's proposed tariff revision and requiring refunds with interest within 90 days of the order. The refund with interest of approximately $10.3 million was made in May 2003.

Northern Border Pipeline is required to file a rate case with the FERC to be effective no later than May 2006. Refer to Section XIV.H.1.c., "FERC Imposed Tariff Adjustments" for further information.

7. Environmental Regulation

The operations of the Pipeline Businesses are subject to complex federal, state and local laws and regulations relating to the protection of health and the environment, including laws and regulations that govern the handling and release of natural gas and liquid hydrocarbon materials. As with the petroleum and natural gas industry in general, complying with current and anticipated environmental laws and regulations increases the Pipeline Businesses' overall cost of doing business, including the Pipeline Businesses' capital costs to construct, maintain, and upgrade equipment and facilities. While these laws and regulations affect the Pipeline Businesses' maintenance capital expenditures and net income, CrossCountry believes that they do not affect the Pipeline Businesses' competitive position because the operations of their competitors are similarly impacted.

Violations of environmental laws or regulations can result in additional costs arising from correcting non-complying conditions or the imposition of significant administrative, civil or criminal fines or penalties and, in some instances, injunctions banning or delaying certain activities. The Pipeline Businesses have ongoing programs designed to keep their facilities in compliance with pipeline safety and environmental requirements. Although CrossCountry believes that the Pipeline Businesses' operations and facilities are in general compliance in all material respects with applicable environmental and safety regulations, risks of substantial costs and liabilities are inherent in pipeline and gas processing operations, and CrossCountry cannot provide any assurances that they will not incur such costs and liabilities. Moreover, it is possible that other developments, such as increasingly strict environmental and safety laws, regulations and enforcement policies thereunder, and claims for damages to property or persons resulting from the Pipeline Businesses' operations, could result in substantial costs and liabilities. If the Pipeline Businesses are unable to recover such resulting costs, earnings and cash distributions could be adversely affected.

There are also risks of accidental releases into the environment associated with the Pipeline Businesses' operations, such as leaks of natural gas from the pipelines. Such accidental releases by the pipelines could, to the extent not insured, subject CrossCountry or the Pipeline Businesses to potential liabilities arising from environmental cleanup and restoration costs, claims made by neighboring landowners or other third parties for personal injury or property damage, and fines or penalties for any related violations of environmental laws or regulations.

In addition, processing plants and gathering facilities owned by Northern Border Partners are subject to Canadian national, provincial, and local laws and regulations relating to safety and the protection of the environment, which include the following Alberta laws: the Energy Resources Conservation Act, the Oil and Gas Conservation Act, the Pipeline Act, and the Environmental Protection and Enhancement Act.

Transwestern incurred, and continues to incur, certain costs related to PCBs including costs related to migration of PCBs into certain customers' facilities. These PCBs were originally introduced into the Transwestern system through use of a PCB-based lubricant in the late 1960s and early 1970s. Costs of these remedial activities for 2002 and 2001 were $2.8 million and $0.5 million, respectively. Costs are estimated to be $1.0 million in 2003. Costs for managing PCBs on the Transwestern system for the same periods are generally less than $0.1 million annually.

The State of New Mexico Environment Department on June 12, 2001 issued an Administrative Compliance Order Assessing a Civil Penalty (Action No. AQCA-01-20) with a proposed penalty to Transwestern in the amount of $160,000 for alleged violations of New Mexico air quality regulations associated with an alleged turbine change without a permit modification at the Transwestern Pipeline P-1 compressor station in Roosevelt County, New Mexico. Transwestern and the New Mexico Environment Department have reached a settlement in principle, subject to the execution of appropriate documents.

8. Litigation, Regulatory Proceedings and Investigations

Current and future litigation, regulatory proceedings and governmental audits and investigations could, individually or in the aggregate, have a material and adverse impact on CrossCountry. Refer to Sections IV.C., "Litigation and Government Investigations", IX.A.6., "Regulatory Environment", and IX.D., "Legal Proceedings" for further information on current litigation, regulatory proceedings and governmental investigations that involve or may involve CrossCountry and its subsidiaries and affiliates.

B. Properties

1. General

CrossCountry intends to sublease office space from ENE for its executive offices at 4 Houston Center in Houston, Texas.

The real property of the Transwestern, Florida Gas, and Northern Border Partners pipeline systems fall into two basic categories: (a) parcels that are owned in fee, such as sites for compressor stations, meter stations, pipeline field offices, and communication towers; and (b) parcels where the interest derives from leases, easements, rights-of-way, permits or licenses from landowners or governmental authorities permitting the use of such land for the construction and operation of the pipeline systems. The majority of the property rights are classified in the latter category. The rights to construct and operate the pipeline systems across certain properties were obtained through exercise of the power of eminent domain. Transwestern's, Florida Gas's, and Northern Border Partners' interstate pipeline systems continue to have the power of eminent domain in each of the states in which they operate. However, a portion of their pipelines and associated facilities are located on Native American lands held in trust by the DOI and administered by the Bureau of Indian Affairs. The Pipeline Businesses may not have the power of eminent domain with respect to Native American tribal lands. CrossCountry cannot assure that it will continue to have access to rights-of-way on tribal lands upon expiration of existing right-of-way grants or that it will be able to obtain new rights-of-way on tribal lands upon the expiration of such grants. Refer to Section XIV.H.1.h., "Continued Access to Tribal Lands" for further information.

CrossCountry believes that the Pipeline Businesses have satisfactory title to or the right to use all of the assets needed to operate their pipeline systems. Although title or other rights to certain properties are subject to encumbrances in some cases, such as customary interests generally retained in connection with acquisition of real property, liens that can be imposed in some jurisdictions for government-initiated action to clean up environmental contamination, liens for current taxes and other burdens, and easements, restrictions and other encumbrances to which the underlying properties were subject at the time of contribution to CrossCountry, CrossCountry believes that none of these burdens should materially detract from the value of the Pipeline Businesses or from its interest in them, and none should materially interfere with its use in the operation of the Pipeline Businesses.

2. Transwestern

Transwestern holds the right, title and interest to its pipeline system. Approximately 958 acres of Transwestern's property are held in fee, which consist of compressor stations, meter stations, radio towers, warehouses, and pipeline fee strips granted in lieu of rights-of-way. The majority of Transwestern's pipeline system is constructed on rights-of-way granted by the apparent record owners of the property or leases or permits from governmental authorities such as the Bureau of Land Management, the National Forest Service, and the State of Arizona. Several rights-of-way for Transwestern's pipelines and other real property assets are shared with other pipelines and other assets owned by third parties. The owners of the other pipelines may not have commenced or concluded eminent domain proceedings for some rights-of-way. In some instances, lands over which rights-of-way have been obtained are subject to prior liens that have not been subordinated to the right-of-way grants. Transwestern has obtained permits from public authorities to cross over or under, or to lay facilities in or along, water courses, county roads, municipal streets and state highways, and in some instances, these permits are revocable at the election of the grantor. Transwestern has also obtained permits from railroad companies to cross-over or under lands or rights-of-way, many of which are also revocable at the grantor's election. Transwestern has the right of eminent domain to acquire the rights-of-way and lands necessary for Transwestern's pipeline system and has used this power in order to acquire certain of the real property interests necessary for its pipeline system.

On November 13, 2001, Transwestern entered into a credit agreement with Citicorp North America, Inc., as Paying Agent, and Citicorp North America, Inc. and JPMCB, as

Co-Administrative Agents, pursuant to which Transwestern granted a first-priority security interest in all of the property of Transwestern to the paying agent.

A portion of the Transwestern pipeline system and related facilities are located on Native American lands, including on those of the Navajo Nation, Pueblo of Laguna, Southern Ute Indian Tribe, and Fort Mojave Indian Reservations. Tribal lands are lands held in trust by the United States for the benefit of a specific Indian tribe. Allotted lands are lands held in trust by the United States for individual Native Americans or their heirs. Transwestern has the right of eminent domain with respect to allotted lands. In 1959, Transwestern was granted two compressor station leases on Navajo Nation tribal lands by the DOI. These leases, which had primary terms of 25 years and optional additional 25-year terms, will expire in 2009. In 2001 Transwestern was granted an extension for various right-of-way grants by the DOI for approximately 347 miles of pipeline on Navajo tribal lands. This extension expires in 2009. Transwestern has filed an application for the renewal of a grant of right-of-way for 20 years of approximately 44 miles across allotted lands on the Navajo Nation. The current right-of-way grants on allotted lands will expire on December 31, 2003 or April 14, 2009.

In 2001, Transwestern was granted a renewal of a right-of-way for a compressor station and approximately 31 miles of Pueblo of Laguna tribal lands by the DOI. This renewal will expire in 2022. Transwestern is in the process of negotiating a renewal or obtaining an easement pursuant to eminent domain proceedings of approximately one mile of pipeline right-of-way across Pueblo of Laguna allotted lands that expired on December 29, 2002.

In 1999, Transwestern was granted a renewal of a right-of-way for approximately three miles of tribal lands on the Fort Mojave reservation by the DOI. This renewal will expire in 2019.

In 1990, a predecessor in interest to Transwestern, Northwest, was granted a right-of-way across approximately seven miles of Southern Ute tribal lands by the DOI. This right-of-way expires in September 2005. By letter dated May 27, 2003, representatives for the Southern Ute tribe notified Transwestern that the Southern Ute's Tribe's 1996 resolution, which had approved partial assignment of Northwest's interest in the grant of right-of-way, had been revoked in a May 19, 2003 resolution. By letter dated September 2, 2003, representatives for the Southern Ute tribe stated that Transwestern's failure to file an application to obtain the Southern Ute Tribal Council's approval of the transfer of the interest in the right-of-way from Northwest by September 15, 2003 would result in legal action. Transwestern representatives have contacted the representatives for the Southern Ute tribe concerning the matter and further discussions are scheduled. An application by Transwestern for approval of the assignment of this interest from Northwest has been in the possession of the DOI since 1999 with no action taken. Neither the 1990 grant of right-of-way nor the 1990 tribal resolution that reflected tribal consent for the 1990 grant of right-of-way provide that consent of the Southern Ute's Tribe or the DOI is required for an assignment of an interest in the 1990 grant or right-of-way. Further, the 1948 General Right-of-Way Act, which authorized the 1990 grant of right-of-way, and the DOI regulations issued under that Act, do not require tribal or DOI consent or approval of assignments of rights-of-way. Refer to Section XIV., "Risk Factors and Other Factors to be Considered" for further information.

CrossCountry cannot assure that it will continue to have access to rights-of-way on tribal lands upon expiration of existing right-of-way grants or that it will be able to obtain new rights-of-way on tribal lands upon the expiration of such grants. Refer to Section XIV.H.1.h., "Continued Access to Tribal Lands" for further information.

3. Citrus

None of Citrus, Citrus Trading, or Citrus Energy Services have any significant tangible properties.

Florida Gas holds the right, title, and interest to its pipeline system. Approximately 948 acres of Florida Gas's property are held in fee which consist of compressor stations, meter stations, radio towers, warehouses, and fee strips granted in lieu of rights-of-way. Substantially all of Florida Gas's pipeline system is constructed on rights-of-way granted by the apparent record owners of the property or leases or permits from governmental authorities such as the Texas General Land Office, the United States Forest Service, and the Mineral Management Services. Several rights-of-way for Florida Gas's pipeline system and other real property assets are shared with other pipelines and other assets owned by third-parties. The owners of the other pipelines may not have commenced or concluded eminent domain proceedings for some rights-of-way. In some instances, lands over which rights-of-way have been obtained are subject to prior liens that have not been subordinated to the right-of-way grants. Florida Gas has obtained permits from public authorities to cross over or under, or to lay facilities in or along, water courses, county roads, municipal streets, and state highways, and in some instances, these permits are revocable at the election of the grantor. Florida Gas has also obtained permits from railroad companies to cross-over or under lands or rights-of-way, many of which are also revocable at the grantor's election. In some cases, property for pipeline purposes was purchased in fee. Florida Gas has the right of eminent domain to acquire the rights-of-way and lands necessary for its pipelines and has used this power in order to acquire certain of the real property interests it owns.

The FTA is planning for several turnpike widening projects, which may over the next ten years impact one or more of Florida Gas's mainlines co-located in the FTA's right-of-way. The most immediate projects are five Sunshine State Parkway projects, which are proposed to overlap Florida Gas's pipelines, for a total of approximately 25 miles. Under certain conditions, the existing agreement between Florida Gas and the FTA calls for the FTA to pay for any new right-of-way needed for the relocation projects and for Florida Gas to pay for construction costs. The actual amount of miles of pipe to be impacted ultimately, and the relocation cost and/or right-of-way cost, recoverable through rates, is undefined at this time due to the preliminary stage of FTA's planning process.

4. Northern Plains

Northern Plains does not hold the right, title, and interest in any tangible properties.

Northern Border Pipeline, Midwestern, and Viking hold the right, title and interest in their pipeline systems. Approximately 90 miles of Northern Border Pipeline's pipeline system are located on fee, allotted, and tribal lands within the exterior boundaries of the Fort Peck Indian Reservation in Montana. Tribal lands are lands owned in trust by the United States for the Fort Peck Tribes and allotted lands are lands owned in trust by the United States for an individual Indian or Indians. Northern Border Pipeline has the right of eminent domain with respect to allotted lands.

In 1980, Northern Border Pipeline entered into a pipeline right-of-way lease with the Fort Peck Tribal Executive Board, for and on behalf of the Assiniboine and Sioux Tribes of the Fort Peck Indian Reservation. This pipeline right-of-way lease, which was approved by the DOI in 1981, granted to Northern Border Pipeline the right and privilege to construct and operate its pipeline on certain tribal lands. This pipeline right-of-way lease expires in 2011. Northern Border Pipeline also obtained a right-of-way across allotted lands located within the reservation boundaries. Most of the allotted lands are subject to a perpetual easement either granted by the Bureau of Indian Affairs for and on behalf of individual Indian owners or obtained through condemnation. Several tracts are subject to a right-of-way grant that has a term of fifteen years, expiring in 2015.

Bear Paw Energy L.L.C., Border Midstream Services Ltd., and Crestone Energy Ventures, through its membership interest in Bighorn Gas Gathering, L.L.C., Lost Creek Gathering Company, L.L.C., and Fort Union Gas Gathering, L.L.C. hold the right, title, and interest in their gathering and processing facilities, which consist of low and high pressure gas gathering lines, compression and measurement installations and treating, processing and fractionation facilities. The real property rights for these facilities are derived through fee ownership, leases, easements, rights-of-way, and permits.

Black Mesa holds title to its pipeline and pump stations. The real property rights for Black Mesa facilities are derived through fee ownership, leases, easements, rights-of-way and permits. Black Mesa holds rights-of-way grants from private landowners as well as the Navajo Nation and the Hopi Tribe. These rights-of-way grants extend for terms at least through December 31, 2005, the date that Black Mesa's transportation contract with Peabody Western Coal is presently scheduled to end.

C. Historical Financials, Projections and Valuation

1. Historical Financials

Refer to Appendix I: "CrossCountry Historical Financials" for historical financial information on Citrus and Transwestern and references to Northern Border Partners' historical financial information filed with the SEC.

2. Projections

In conjunction with formulating the Plan, as set forth on Appendix J: "CrossCountry Financial Projections – 2003-2006", financial projections have been prepared for CrossCountry for the four years ending December 31, 2006. The projections for the fiscal year ended December 31, 2003, include unaudited actual results through June 30, 2003. The projections are based on a number of assumptions made with respect to the future operations and performance of CrossCountry and should be reviewed in conjunction with a review of the principal assumptions set forth on Appendix J: "CrossCountry Financial Projections – 2003-2006". While the projections were prepared in good faith and the Debtors believe the assumptions, when considered on an overall basis, to be reasonable in light of the current circumstances, it is important to note that the Debtors can provide no assurance that such assumptions will be realized and Creditors must make their own determinations as to the reasonableness of such assumptions and the reliability of the projections. Refer to Section XIV., "Risk Factors and Other Factors to be Considered" for a discussion of numerous risk factors that could affect CrossCountry's financial results.

3. Valuation

Also, in conjunction with formulating the Plan, the Debtors determined that it was necessary to estimate the post-confirmation equity value of CrossCountry. Accordingly, Blackstone and the Debtors formulated such a valuation, which is utilized in the Blackstone model. Such valuation is based, in part, on the financial projections prepared by CrossCountry management and included in Appendix J: "CrossCountry Financial Projections – 2003-2006". This valuation analysis was used, in part, for the purpose of determining the value of CrossCountry to be distributed to Creditors pursuant to the Plan and to analyze the relative recoveries to Creditors under the Plan.

a. Estimated Value. Based upon the methodology described below, the Blackstone Model utilizes an estimated equity value of $1.490 billion, as the mid-point within a valuation range of $1.410 billion to $1.571 billion for CrossCountry at December 31, 2003. Therefore, assuming 75 million shares of new CrossCountry Common Stock will be issued and distributed to or on behalf of Creditors pursuant to the Plan, the value of such stock is estimated to range from $18.79 to $20.95 per share; provided, however, that such estimate does not reflect any dilution resulting from any long-term equity incentive compensation plan(s) as may be adopted by CrossCountry. However, it is anticipated that the impact of any such plan(s) to be adopted by PGE, CrossCountry and Prisma will, in the aggregate, represent less than 1% of the overall value to be distributed under the Plan. The estimated value is based upon a variety of assumptions, as referenced below under "Variances and Risks," deemed appropriate under the circumstances. The estimated value per share of the CrossCountry Common Stock may not be indicative of the price at which the CrossCountry Common Stock will trade when and if a market for the CrossCountry Common Stock develops, which price could be lower or higher than the estimated value of the CrossCountry Common Stock. Accordingly, there can be no assurance that the CrossCountry Common Stock will subsequently be purchased or sold at prices comparable to the estimated values set forth above. Refer to Section XIV., "Risk Factors and Other Factors to be Considered" for a discussion of numerous risk factors that could affect CrossCountry's financial results.

b. Methodology. Two methodologies were used to derive the value of CrossCountry based on the financial projections attached as Appendix J: "CrossCountry Financial Projections – 2003-2006": (i) a comparison of CrossCountry and its projected performance to comparable companies and how the market values them, and (ii) a comparison of CrossCountry and its projected performance to comparable companies in precedent transactions.

The market-based approach involves identifying a group of publicly traded companies whose businesses are comparable to those of CrossCountry or significant portions of CrossCountry's operations, and then calculating ratios of various financial results to the public market values of these companies. The ranges of ratios derived are applied to the CrossCountry projections to arrive at a range of implied values. Similarly, the comparable transaction approach involves calculating various financial ratios based on the prices paid for companies in similar lines of business as CrossCountry, and applying these ratios to the CrossCountry projections to arrive at a range of values.

4. Variances and Risks. Refer to Section XIV.C., "Variance from Valuations, Estimates and Projections" for a discussion regarding the potential for variance from the projections and valuation described above and Section XIV., "Risk Factors and Other Factors to be Considered" in general for a discussion of risks associated with CrossCountry.

ESTIMATES OF VALUE DO NOT PURPORT TO BE APPRAISALS NOR DO THEY NECESSARILY REFLECT THE VALUES THAT MAY BE REALIZED IF ASSETS ARE SOLD. THE ESTIMATES OF VALUE REPRESENT HYPOTHETICAL EQUITY VALUES ASSUMING THE IMPLEMENTATION OF CROSSCOUNTRY'S BUSINESS PLAN AS WELL AS OTHER SIGNIFICANT ASSUMPTIONS. SUCH ESTIMATES WERE DEVELOPED SOLELY FOR PURPOSES OF FORMULATING AND NEGOTIATING A CHAPTER 11 PLAN FOR THE DEBTORS AND ANALYZING THE PROJECTED RECOVERIES THEREUNDER. THE ESTIMATED EQUITY VALUE IS HIGHLY DEPENDENT UPON ACHIEVING THE FUTURE FINANCIAL RESULTS SET FORTH IN THE PROJECTIONS AS WELL AS THE REALIZATION OF CERTAIN OTHER ASSUMPTIONS THAT ARE NOT GUARANTEED.

THE VALUATIONS SET FORTH HEREIN REPRESENT ESTIMATED VALUES AND DO NOT NECESSARILY REFLECT VALUES THAT COULD BE ATTAINABLE IN PUBLIC OR PRIVATE MARKETS. THE EQUITY VALUE ASCRIBED IN THE ANALYSIS DOES NOT PURPORT TO BE AN ESTIMATE OF THE MARKET VALUE OF CROSSCOUNTRY STOCK DISTRIBUTED PURSUANT TO A CHAPTER 11 PLAN. SUCH TRADING VALUE, IF ANY, MAY BE MATERIALLY DIFFERENT FROM THE EQUITY VALUE RANGES ASSOCIATED WITH THE VALUATION ANALYSIS.

ADDITIONALLY, THE VALUES SET FORTH HEREIN ASSUME CERTAIN LEVELS OF RATES FOR THE TRANSPORTATION OF NATURAL GAS AS SET BY FERC. SUCH RATES ARE HIGHLY REGULATED AND SUBJECT TO PERIODIC CHANGES. THERE IS NO GUARANTEE THAT THE CURRENT RATE LEVELS WILL NOT CHANGE MATERIALLY IN THE FUTURE OR WILL PROVIDE ADEQUATE REIMBURSEMENT FOR THE SERVICES PROVIDED BY CROSSCOUNTRY. ANY SUCH CHANGES ARE ENTIRELY BEYOND CROSSCOUNTRY'S CONTROL AND MAY HAVE A MATERIAL ADVERSE IMPACT ON ACTUAL RESULTS. FURTHER, CROSSCOUNTRY OPERATES IN A HEAVILY GOVERNMENT REGULATED INDUSTRY. IN THE ORDINARY COURSE OF ITS BUSINESS, CROSSCOUNTRY IS SUBJECT REGULARLY TO INQUIRIES, INVESTIGATIONS AND AUDITS BY FEDERAL AND STATE AGENCIES THAT OVERSEE VARIOUS NATURAL GAS PIPELINE REGULATIONS. CHANGES TO THE CURRENT REGULATORY ENVIRONMENT MAY

HAVE A MATERIAL ADVERSE IMPACT ON CROSSCOUNTRY'S ACTUAL RESULTS. REFER TO THE ENTIRETY OF SECTION IX., "CROSSCOUNTRY ENERGY CORP." AND SECTION XIV., "RISK FACTORS AND OTHER FACTORS TO BE CONSIDERED" FOR FURTHER DISCUSSION ON THESE AND OTHER RISKS ATTENDANT WITH THE NATURAL GAS PIPELINE INDUSTRY.

D. Legal Proceedings

In addition to the matters described below, from time to time the Pipeline Businesses to be contributed to CrossCountry pursuant to the formation transactions are subject to other claims and litigation arising in the ordinary course of business. Although the final outcome of any legal proceeding cannot be predicted with certainty, CrossCountry does not expect disposition of these matters to have a materially adverse effect on its financial position, results of operation or cash flows. Refer to Section IV.C., "Litigation and Government Investigations" for further information regarding significant pending litigation.

1. In re Natural Gas Royalties Qui Tam Litigation, MDL Docket No. 1293 (D. Wy.), previously Civil Action Nos. 97-D-1421 (D. Colo.) and 97-2087 (E.D. La.) and other consolidated cases. This proceeding was initiated against Transwestern, Northern Border Pipeline, Citrus, Florida Gas, and certain of their affiliates by a private person on behalf of the United States of America under the FCA. The relator, as the plaintiff is called in FCA actions, alleges that the defendants mismeasured the volume and heating content of natural gas produced from federal and Indian leases. The relator further alleges that, as a result, the defendants caused others to underpay the royalties that were due to the United States government. The Pipeline Businesses believe that their measurement practices conformed to the terms of their FERC Gas Tariffs, which are filed with and approved by FERC. As a result, the Pipeline Businesses believe that they have meritorious defenses (including FERC-related affirmative defenses, such as the filed rate/tariff doctrine, the primary/exclusive jurisdiction of FERC, and that the Pipeline Businesses complied with the terms of their tariffs) to the lawsuit, which they are defending vigorously.

2. Will Price, et al. v. Gas Pipelines, et al. 26th Judicial District Court of Stevens County, Kansas (Case No. 99 CV-30). This proceeding is a putative class action brought on behalf of gas producers, working interest owners, royalty owners, and overriding royalty owners against Transwestern and Florida Gas, among others. The plaintiffs allege that the defendants mismeasured the volume and heating content of natural gas. The plaintiffs further allege that the defendants, acting alone or in conspiracy with each other, underpaid the gas producers for the production of natural gas and caused others to underpay royalty owners. The Pipeline Businesses believe that their measurement practices conformed to the terms of their FERC gas tariffs, which are filed with and approved by FERC. As a result, the Pipeline Businesses believe that they have meritorious defenses (including FERC-related affirmative defenses, such as the filed rate/tariff doctrine, the primary/exclusive jurisdiction of FERC, and that the pipelines complied with the terms of their tariffs) to the complaint and are defending the suit vigorously. On April 10, 2003, the judge declined to certify the class. On May 12, 2003, the plaintiff filed a motion for leave to file an amended petition. This would be the fourth amended petition and only includes defendants who were not part of the motion to dismiss for lack of personal jurisdiction. On July 28, 2003, the judge granted leave to file the fourth amended petition and it did not include Transwestern or Florida Gas. Therefore, Transwestern and Florida Gas are no longer named defendants in the litigation.

3. Citrus Trading Corp. v. Duke Energy LNG Sales, Inc., District Court of Harris County, Texas, (Case No. 2003-12166). On March 7, 2003, Citrus Trading filed a declaratory order action, involving a contract between it and Duke Energy LNG. Citrus Trading requested that the court declare that Duke Energy LNG breached the parties' natural gas purchase contract by failing to provide sufficient volumes of gas to Citrus Trading. The suit seeks damages and a judicial determination that Duke Energy LNG has not suffered a "loss of supply" under the parties' gas purchase contract, which could, if such "loss of supply" continued, have given rise to the right of Duke Energy LNG to terminate the contract at some point in the future. On April 14, 2003, Duke Energy LNG sent Citrus Trading a notice that the contract was terminated effective as of April 16, 2003. Duke Energy LNG has continued to refuse to perform under the contract. Duke Energy LNG has answered and filed a counterclaim, arguing that Citrus Trading has breached a "resale restriction" on the gas and that Citrus Trading failed to timely increase the amount of a letter of credit. Citrus Trading disputes that it has breached the agreement, or that any event has given rise to a right to terminate by Duke Energy LNG. On April 29, 2003, Duke Energy LNG filed to remove the case to federal court. On May 28, 2003, Citrus Trading filed a motion to remand the case to state court. On June 2, 2003, Citrus Trading notified Duke Energy LNG that because Duke Energy LNG had not cured its default, Citrus Trading terminated the agreement effective as of June 5, 2003. On August 8, 2003, Citrus Trading sent its final "termination payment" invoice to Duke Energy LNG in an amount of $187 million. On July 31, 2003, the federal court granted Citrus Trading's motion and remanded the case to state court. Discovery is underway. On August 18, 2003, Duke Energy LNG filed a Third-Party Petition against its Algerian suppliers ("Sonatrach" and "SonaTrading Amsterdam") for ceasing to ship supplies of LNG to Duke Energy LNG. Citrus Trading opposed this Petition since, among other things, even if a failure by Duke Energy LNG to receive LNG supply from a supplier such as Sonatrach or SonaTrading Amsterdam occurred, Duke Energy LNG was nevertheless required to continue to furnish supplies to Citrus Trading for a stated period of time. On October 6, 2003, the court ruled that, although Duke Energy LNG may attempt to acquire service on its Algerian suppliers, Duke Energy LNG's claims against the suppliers would be tried separately (and thus, not delay or otherwise impact the prosecution of Citrus Trading's claim against Duke Energy LNG).

Also on October 6, 2003, Citrus Trading filed an Amended Petition, alleging wrongful termination against Duke Energy LNG and containing the termination damages. On October 17, 2003, the court reversed its October 6 ruling that Duke's claim against the Algerian suppliers would be tried separately. On October 24, 2003, and October 28, 2003, Duke Energy LNG filed first and second amended Third Party Petitions, claiming that the Algerians' breach of contract (as determined by an arbitration proceeding decided in London, England) and liability to Duke Energy LNG results in the Algerian suppliers being responsible for any damages the court may ultimately find Duke Energy LNG owes to Citrus Trading. On October 29, 2003, SonaTrading Amsterdam filed a special appearance in state court claiming lack of personal jurisdiction and removed Citrus Trading Corp. v. Duke Energy Sales LNG, Inc. to federal court. This could delay Citrus Tradings' recovery of damages. This is a disputed matter, and there can be no assurance as to what amounts, if any, Citrus Trading will recover.

4. FERC Order to Respond. On August 1, 2002, FERC issued to Transwestern an order to respond. The order required Transwestern to provide written responses stating why FERC should not find that: (1) Transwestern violated FERC's accounting regulations by failing to maintain written cash management agreements with ENE; and (2) the secured loan transactions entered into by Transwestern in November 2001 were imprudently incurred and why the costs arising from such transactions should be passed on to ratepayers. Transwestern filed a response to the order and subsequently entered into a settlement with FERC staff that resolved the issues raised by the order. FERC has approved this settlement; however, a group of Transwestern's customers has filed a request for clarification and/or rehearing of FERC order approving the settlement. This customer group claims that there is an inconsistency between the language of the settlement agreement and the language of the FERC order approving the settlement. This alleged inconsistency relates to Transwestern's ability to pass on to its ratepayers the costs of any replacement or refinancing of the secured loan transactions entered into by Transwestern in November 2001. Transwestern has filed a response to the customer group's request for rehearing and/or clarification and this matter is currently awaiting FERC action.

5. Eugene Lavender, et al. v. Florida Gas Transmission Company, et al., U.S. District Court, Southern District of Alabama (Case No. CV-02-0361-JG-L). This proceeding is associated with the construction and operation of Florida Gas Compressor Station Number 44, which was built as part of the Phase V Expansion. The plaintiffs allege negligence, wantonness, nuisance, strict liability, personal injury, loss of wages, and inverse condemnation. This suit is the consolidation of 13 different lawsuits filed in Mobile County Circuit Court that were removed to federal court. There are 25 individual plaintiffs owning 13 different tracts of land in the vicinity of Compressor Station Number 44. Mediation was held on July 22, 2003 but was unsuccessful. In an order dated August 6, 2003 the Court granted summary judgment against the plaintiffs on a number of claims, including those that might result in punitive damages, thereby limiting plaintiffs' claims to nuisance and negligence. Prior to this order the plaintiffs stated their claim at trial would be $4,295,000. On August 15, 2003, plaintiffs filed a Motion to Reconsider, Alter or Amend the Court's summary judgment order that was denied by order dated September 11, 2003. The parties have reached a settlement in principle, subject to the execution of appropriate documents.

6. Florida Gas Transmission Co. v. Wright, et al., 20th Judicial Circuit Court, Charlotte County, Florida (Case No. 00-1902-CA). This proceeding relates to a condemnation by Florida Gas for the acquisition of a right-of-way by Florida Gas during its Phase IV Expansion. An Easement Agreement between Florida Gas and the owner of the property was executed but the owner threatened to commence a post-pipeline construction lawsuit for damages. The owner agreed to stipulate to taking of the right-of-way by Florida Gas for the agreed upon price but is contesting the route and the amount of the damages to the land. Florida Gas has filed a motion to dismiss, and at a hearing on July 28, 2003, the motion was denied. The owner's demand for damages is $1,872,500 excluding fees and costs.

7. Florida Gas Transmission Co. v. Battista, et al., 20th Judicial Circuit Court, Charlotte County, Florida (Case No. 00-319-CA). This proceeding, which relates to a condemnation by Florida Gas for the acquisition of a right-of-way by Florida Gas during its Phase IV Expansion, involves a claim by the owner of the land for possible sod crop damage due to drainage obstruction by Florida Gas. Florida Gas has filed a motion to dismiss, and at a hearing on July 28, 2003, the motion was denied. The owner's demand is $1,469,000 excluding fees and costs.

8. Moye v. Exxon Corp., et al., 35th Judicial Circuit Court, Monroe County, Alabama (Case No. CV-98-20). In this proceeding, a mineral owner seeks damages for mismeasurement of natural gas production, as well as, subsequent underpayment of royalties against defendants ExxonMobil, et al., alleging the duty to measure properly under contracts with royalty owners. The pipelines, including Florida Gas, were subsequent measurers and are alleged to have measured gas incorrectly. Damages for underpayment of royalties and mismeasurement are unspecified. The mineral owner was granted class certification as to ExxonMobil only; Florida Gas was not included in the class certification order.

9. Air Liquide American Corp., et al. v. United States Army Corps of Engineers, et al., U.S. District Court, Southern District of Texas, Houston Division (Case No. H-98-3982). Florida Gas is among sixteen plaintiffs seeking reimbursement from the Port Authority of Houston for the cost of moving their pipelines in the Houston Ship Channel. In January 2002, the court ordered the Port Authority of Houston to pay the cost of moving the pipelines. The Port Authority has appealed and oral arguments took place on September 3, 2003. The potential recovery for Florida Gas is approximately $4 million.

10. Assiniboine & Sioux Tribes of the Fort Peck Indian Reservation v. Northern Border Pipeline Co., Tribal Court (No. 01-7-243). On July 31, 2001, the Assiniboine and Sioux Tribes of the Fort Peck Indian Reservation filed suit in Tribal Court against Northern Border Pipeline to collect more than $3 million in back taxes, with interest and penalties relating to a utilities tax on certain of Northern Border Pipeline rights-of-way within the Fort Peck Reservation. During mediation the parties agreed in principle to a settlement on pipeline right-of-way lease and taxation issues, subject to final documentation and necessary governmental approvals.

E. Directors

On the Effective Date, CrossCountry's board of directors shall consist of individuals designated by the Debtors, after consultation with the Creditors' Committee, all of which shall be disclosed prior to the Confirmation Hearing. In the event that, during the period from the Confirmation Date up to and including the Effective Date, circumstances require the substitution of one (1) or more persons selected to serve, the Debtors shall file a notice thereof with the Bankruptcy Court and, for purposes of section 1129 of the Bankruptcy Code, any such replacement person, designated after consultation with the Creditors' Committee, shall be deemed to have been selected or disclosed prior to the Confirmation Hearing. Thereafter, the terms and manner of selection of the directors of CrossCountry shall be as provided in the CrossCountry Certificate of Incorporation and CrossCountry By-laws, as the same may be amended. Each director will serve until a successor is elected and qualified or until his earlier resignation or removal.

Set forth below is biographical information for five individuals who are currently members of CrossCountry's board of directors on the Effective Date. Each of these directors has held his position at CrossCountry since CrossCountry's formation or shortly thereafter. It is expected that these directors will comprise the board of directors on the Effective Date. Currently there is an interim management team in place for CrossCountry.

1. Raymond S. Troubh

Mr. Troubh, 77, is a financial consultant. He has been an ENE director since November 27, 2001 and Chairman of the Board of ENE since November 14, 2002. He is also a director of ARIAD Pharmaceuticals, Inc., Diamond Offshore Drilling, Inc., General American Investors Company, Gentiva Health Services, Inc., Petrie Stores Liquidating Trust (Trustee), Triarc Companies, Inc., and WHX Corporation. He formerly was a partner of Lazard Freres and Co. and previously served on the boards of several public companies such as Time Warner, Starwood Hotels, and America West Airlines, among others.

2. Corbin A. McNeill, Jr.

Mr. McNeill, 63, is the retired chairman and CEO of Exelon Corporation, which was formed in October 2000 by the merger of PECO Energy Company and Unicom Corporation. Prior to the merger, he was chairman, president, and CEO of PECO Energy. Mr. McNeill completed a 20 year career with the U.S. Navy in 1981 and then joined the New York Power Authority as resident manager of the James A. Fitzpatrick nuclear power plant. He also worked at Public Service Electric and Gas Company prior to joining PECO in 1988 as executive vice president, nuclear. Mr. McNeill has been a director of ENE since May 30, 2002. He also serves on the boards of the Electric Power Research Institute and Associated Electric & Gas Services Limited.

3. James J. Gaffney

Mr. Gaffney, 63, is a financial consultant specializing in companies that have emerged from bankruptcy proceedings, undergone consensual restructurings, or have otherwise had financial/operational difficulties. Mr. Gaffney has served on the boards of General Aquatics Inc., Ayers Chairmakers Inc., Brown Jordan Company, General Refractories Company, Imperial Sugar Company, SCP Pool Inc., and Hexcel Inc. Mr. Gaffney earned a Master of Business Administration degree from New York University in 1967 and a Bachelors of Business Administration degree from St. John's University in 1963.

4. Gary L. Rosenthal

Mr. Rosenthal, 54, is the President of Heaney Rosenthal Inc., a private equity financial consultant. Mr. Rosenthal has served on the boards of Hydrochem Holding Inc., Axia Incorporated, Wheatley TXT Corp., Dresser Inc., Oil States International, Inc., Pioneer Companies Inc., and Texas Petrochemical Holdings Inc. Mr. Rosenthal was a Partner with Vinson & Elkins until 1987, and clerked at the United States Fifth Circuit Court of Appeals. He earned a J.D. from Harvard Law School in 1975, and an A.B. from Harvard University in 1971.

5. Michael L. Muse

Mr. Muse, 54, is an attorney and certified public accountant and has been involved in personal investments, including domestic and foreign oil and gas investments, since 1985, when the airline he co-founded, Muse Air Corporation, was sold to Southwest Airlines Co. Prior to founding Muse Air Corporation in 1980, Mr. Muse was a Tax Manager at Price Waterhouse & Co., and Counsel – Contracts and Administration, and Vice President – Finance and Administration & Chief Financial Officer, at Southwest Airlines Co. Mr. Muse earned a B.A. in Economics from Vanderbilt and a J.D. from the University of Texas School of Law.

F. Certain Relationships and Related Transactions

1. Formation of CrossCountry

CrossCountry was incorporated in the State of Delaware on May 22, 2003 for the purpose of acquiring the CrossCountry Equity Interests. On June 24, 2003, CrossCountry and the CrossCountry Enron Parties entered into the CrossCountry Contribution and Separation Agreement, which governs the contribution of the CrossCountry Equity Interests. On September 25, 2003, the Bankruptcy Court issued an order approving the transfer of the CrossCountry Equity Interests and the shared services assets from the CrossCountry Enron Parties to CrossCountry and other related transactions, pursuant to the CrossCountry Contribution and Separation Agreement. The closing of the CrossCountry Contribution and Separation Agreement is planned to occur in the fourth quarter of 2003, at which time CrossCountry and the CrossCountry Enron Parties will enter into certain ancillary agreements, including the Transition Services Agreement, the Transition Services Supplemental Agreement, the Tax Sharing Agreement, the Ardmore Collocation License Agreement, and the Cross License Agreement, as more fully described below. On October 9, 2003 pursuant to an order of the Bankruptcy Court, Enron Operations, L.P. was dissolved, and EOC Preferred, a wholly owned subsidiary of ENE, became its successor in interest under the CrossCountry Contribution and Separation Agreement. Immediately following the dissolution of Enron Operations, L.P., ETS and EOS were converted to Delaware limited liability companies.

The ancillary agreements, together with the CrossCountry Contribution and Separation Agreement, will govern the relationship between the CrossCountry Enron Parties and CrossCountry subsequent to the contribution of the CrossCountry Equity Interests and provide for the allocation of tax, the performance of certain interim services, and the definition of other rights and obligations until the distribution of shares of capital stock of CrossCountry pursuant to the Plan. In addition, the CrossCountry Contribution and Separation Agreement sets forth certain shareholder protection provisions with respect to CrossCountry and indemnification obligations of the CrossCountry Enron Parties and CrossCountry, as more fully described below.

a. CrossCountry Contribution and Separation Agreement. The CrossCountry Enron Parties, pursuant to the CrossCountry Contribution and Separation Agreement, will contribute the CrossCountry Equity Interests to CrossCountry in exchange for shares of CrossCountry common stock commensurate with the value of the CrossCountry Equity Interests contributed. In addition, certain of the CrossCountry Enron Parties will contribute information technology and other assets to be used by each of the Pipeline Businesses.

The shares of CrossCountry common stock to be issued in connection with the CrossCountry Contribution and Separation Agreement are set forth below:

Equity Interest/Asset	Contributed By	Shares of CrossCountry Common Stock To Be Issued in Exchange for Equity Interest
500 shares of Class B common stock, par value $1.00 per share, of Citrus	ENE	2,400 shares of Common Stock
400 shares of common stock, par value $1.00 per share, of Northern Plains	ENE	644 shares of Common Stock
800 shares of common stock, par value $0.01 per share, of Transwestern Holding, and the voting trust certificate for two hundred (200) shares of common stock, par value $0.01 per share, of Transwestern Holding	ETS	2,182 shares of Common Stock
1,000 shares of common stock, par value $0.01 per share of CGNN	ETS	32 shares of Common Stock
Transfer of certain shared services assets	ETS	7 shares of Common Stock
1,000 shares of common stock, par value $1.00 per share, of NBP Services	EOC Preferred	1 share of Common Stock
Transfer of certain shared services assets	EOS	9 shares of Common Stock

The CrossCountry Contribution and Separation Agreement contemplates the eventual distribution by a CrossCountry Distributing Company to creditors of shares of CrossCountry common stock under the Plan, and the following actions to be taken by CrossCountry and the CrossCountry Enron Parties to effectuate that distribution:

- each CrossCountry Enron Party and CrossCountry will take necessary actions to conform the organizational documents and capital structure of the CrossCountry Distributing Company as necessary to effectuate the distribution;

- CrossCountry will and, if applicable, the CrossCountry Enron Parties will cause the Distributing Company to prepare, file, and use commercially reasonable efforts to have declared effective a registration statement on

Form 10 by the SEC and use its reasonable best efforts to have approved an application for listing of its capital stock on a national securities exchange or quoted in one of the NASDAQ markets;

- to the extent provided in the Plan, on the date of the initial distribution of capital stock of the Distributing Company, the shares of CrossCountry common stock held by the CrossCountry Enron Parties will be cancelled or assigned to a Distributing Company, if applicable;

- CrossCountry will and, if applicable, the CrossCountry Enron Parties will cause the Distributing Company to issue the number of shares of its capital stock required by the Plan (with such shares not immediately distributed to creditors being held in a reserve for Disputed Claims), and take all actions necessary to ensure that those shares are duly authorized, validly issued, fully paid and nonassessable and free of any preemptive rights;

- subject to certain exceptions in the CrossCountry Contribution and Separation Agreement, CrossCountry will bear the expenses incurred in connection with a distribution of its shares;

- ENE intends to obtain such consents as are necessary to effect the distribution of capital stock of the CrossCountry Distributing Company pursuant to the Plan. Refer to Section XIV.A.4., "Delayed Distribution or Non-Distribution of Plan Securities" for further information; and

- with respect to any claims relating to pre-contribution obligations (including intercompany notes or receivables) owed by ENE and its affiliates (other than CrossCountry and its subsidiaries) to CrossCountry or any of its subsidiaries, CrossCountry agrees to, and to cause its subsidiaries to, and to cause any assignee or successor in interest to such obligations to agree to, submit a Ballot voting in favor of the Plan, to the extent such claims entitle the holder thereof to vote on the Plan.

(i) Indemnification

(A) Tax Indemnification. ENE has agreed to indemnify the CrossCountry Indemnified Parties against any taxes, or liabilities incurred in connection with taxes, of any subsidiary of CrossCountry that are imposed upon such subsidiary by reason of its being severally liable for any taxes of ENE and its subsidiaries (other than CrossCountry and its subsidiaries) pursuant to Treasury Regulation §1.1502-6(a) or any analogous state, local, or foreign law. This obligation to indemnify terminates upon the closing of the Chapter 11 Cases.

(B) Employee Benefits Indemnification. ENE has agreed to indemnify the CrossCountry Indemnified Parties against any liabilities arising out of any employee benefit plan sponsored by ENE that are imposed upon any CrossCountry subsidiary (i) under Title IV of ERISA or (ii) due to participating employer status in the Enron Corp. Savings Plan. This obligation to indemnify terminates upon the closing of the Chapter 11 Cases.

(C) TGS Related Indemnification. In connection with ENE's investment in TGS, ENE included Transwestern as a member of the "economic group" of ENE-controlled companies, and Transwestern agreed to provide ongoing technical support to the ENE affiliate, EPCA, serving as the Technical Operator for the TGS pipeline. Refer to Section IX.F.2.a., "TGS" for further information. CrossCountry has agreed to provide ENE with written notice of any communication from TGS, EPCA, any direct or indirect stakeholder in TGS (if such communication relates to TGS), or the Argentine government. Regardless of whether ENE has received such notice, ENE may request in writing that CrossCountry cause Transwestern to perform certain services or take certain actions with respect to existing obligations relating to TGS or EPCA. CrossCountry has agreed to cause Transwestern to perform such services or take such actions promptly upon the receipt of such notice, and shall cause Transwestern to perform in a reasonably prudent manner and in accordance with natural gas pipeline industry standards in the United States.

Under the CrossCountry Contribution and Separation Agreement, ENE has agreed to indemnify the CrossCountry Indemnified Parties against any liabilities incurred by CrossCountry in connection with third-party claims arising from ENE's investment in TGS, including potential liabilities that may result from Transwestern's ceasing to be a member of ENE's economic group. However, ENE will have no obligation to indemnify CrossCountry for any such liabilities if (i) CrossCountry fails to provide ENE with a notice of certain communications relating to TGS when required to do so or (ii) such liabilities arise from any action or inaction by Transwestern that is not in accordance with the performance standards or requested by ENE.

CrossCountry has agreed to indemnify the Enron Indemnified Parties against any liabilities incurred by an Enron Indemnified Party as a result of (w) CrossCountry's failure to provide ENE with notice when required to do so, (x) Transwestern's refusal or failure to promptly perform services or actions set forth in a notice from ENE requesting such performance, (y) performance pursuant to such notice that is not in accordance with the performance standard set forth in the CrossCountry Contribution and Separation Agreement or (z) Transwestern's election to perform services or take any action in the absence of a notice requesting performance from ENE, or to perform services or take actions in addition to those specified in any such notice. The obligations to indemnify with respect to TGS-related matters terminate upon the closing of the Chapter 11 Cases.

(D) General Indemnification. In addition to the indemnification obligations described above, CrossCountry and ENE have agreed to indemnify the Enron Indemnified Parties and the CrossCountry Indemnified Parties, respectively, against any liabilities resulting from third-party claims caused by a material breach by such party of the CrossCountry Contribution and Separation Agreement. In addition, CrossCountry has agreed to indemnify the Enron Indemnified Parties against any liabilities arising out of any guaranty (existing on or prior to closing) of any obligation of CrossCountry or its subsidiaries by ENE or any affiliate of ENE (other than CrossCountry and its subsidiaries). Each party's obligation to indemnify pursuant to the general indemnification will terminate upon the initial distribution to creditors of CrossCountry Common Stock pursuant to the terms of the Plan except for the obligation to indemnify against liabilities arising out of a material breach of covenants in the

Contribution and Separation Agreement that by their terms contemplate performance after such date which shall survive for the applicable period of time set forth in such covenant.

(E) Limitations on Indemnification. The CrossCountry Enron Parties, on the one hand, and CrossCountry, on the other hand, shall not be required to indemnify the CrossCountry Indemnified Parties and the Enron Indemnified Parties, respectively, for any liabilities resulting from third-party claims caused by a material breach by such party of the CrossCountry Contribution and Separation Agreement or liabilities arising under the Transition Services Agreement, exceeding $125 million in the aggregate.

(ii) Termination. ENE may unilaterally terminate the CrossCountry Contribution and Separation Agreement at any time in its discretion, subject to the consent of the Creditors' Committee.

Upon the occurrence of an event that is materially adverse to the business, financial condition or assets of CrossCountry and its subsidiaries prior to the closing date, ETS may terminate the CrossCountry Contribution and Separation Agreement if the board of directors of ETS determines in good faith that the exercise of its fiduciary duties requires that ETS terminate the CrossCountry Contribution and Separation Agreement.

(iii) Certain Governance Provisions. From the closing date until the initial distribution of CrossCountry Common Stock pursuant to the terms of the Plan, CrossCountry has agreed that it will not take the following actions without the approval of a majority of CrossCountry's stockholders:

- disposing of any capital stock held directly or indirectly by CrossCountry in certain pipeline and service companies or selling any significant portion of the assets of CrossCountry or such companies;

- entering into any new lines of business or changing the fiscal year;

- establishing or modifying significant accounting methods, practices or policies or significant tax policies;

- registering securities of CrossCountry or certain subsidiaries of CrossCountry for issuance under federal or state securities laws;

- issuing any capital stock of CrossCountry or certain subsidiaries of CrossCountry, or any securities convertible into, or exercisable or exchangeable for, capital stock of CrossCountry or certain subsidiaries of CrossCountry;

- creating or assuming any indebtedness for borrowed money in excess of $40 million in the aggregate for CrossCountry and certain of its subsidiaries, except for renewals, roll-overs, or refinancings of existing indebtedness;

- adopting or materially amending any equity-based bonus or employee benefit plan or program;

- incurring (x) any non-maintenance capital expenditures, or commitments to make non-maintenance capital expenditures, in excess of $15 million in the aggregate per CrossCountry fiscal year and/or per project or group of related projects or (y) annual maintenance capital expenditures, or commitments to make annual maintenance capital expenditures, in excess of $50 million in the aggregate, in each case, by CrossCountry and certain of its subsidiaries;

- compromising or settling litigation in excess of $2 million; or

- entering into any joint venture, partnership, merger, or other business combination transaction.

Until the distribution of CrossCountry Common Stock to Creditors pursuant to the Plan, CrossCountry has agreed that it will cause its controlled subsidiaries not to, and will use commercially reasonable efforts, subject to any applicable fiduciary and/or contractual obligations, to cause its non-controlled subsidiaries not to, engage in the above actions. CrossCountry has also agreed to cause its subsidiaries to include these provisions in their respective certificates of incorporation. Refer to Section XIV.A.4., "Delayed Distribution or Non-Distribution of Plan Securities" for further information.

At the closing, CrossCountry will file an amended and restated certificate of incorporation setting forth the same shareholder protection provisions. ENE has agreed that it will request that the CrossCountry Approval Order provide that CrossCountry may not amend the provisions of its amended and restated certificate of incorporation without first obtaining an order of the Bankruptcy Court permitting such amendment.

Upon the written request (if any) of ENE to CrossCountry, at any time prior to the initial distribution of capital stock of the Distributing Company, the board of directors of CrossCountry will commence an auction process for the sale of certain of its businesses or assets, subject to CrossCountry stockholder approval of the terms and conditions of such sale. ENE has agreed that the CrossCountry Approval Order will provide that CrossCountry must first obtain an order of the Bankruptcy Court authorizing such stockholder approval.

(iv) Transfer of Shared Services Assets. Prior to the closing, EOS and ETS will assign to CrossCountry or a designated subsidiary of CrossCountry certain assets, including certain information technology and the Ardmore Data Center in Houston, Texas, on an "as-is," "where-is" basis. The Ardmore Data Center is the primary internet/telecommunications center for ENE and its affiliates, including the Pipeline Businesses. The servers, storage area network equipment, and phone switch equipment for ENE and its affiliates, including the Pipeline Businesses, are located at Ardmore. Under the Transition Services Agreement described below, CrossCountry agrees to provide support services to ENE relating to the Ardmore Data Center.

(v) Conditions to Closing. In addition to customary conditions to the obligations of the parties, including the absence of material breaches of the CrossCountry Contribution and Separation Agreement, performance of all covenants and agreements and the delivery of all closing documentation, the obligation of the parties under the CrossCountry Contribution and Separation Agreement is conditioned upon (i) obtaining the CrossCountry Approval Order, (ii) the release of all liens on the CrossCountry Equity Interests imposed in connection with ENE's Amended DIP Credit Agreement, (iii) obtaining the necessary consents under Transwestern's credit facility, and (iv) obtaining consent from the FCC.

b. Ancillary Agreements

(i) Transition Services Agreement. At the closing of the transactions contemplated by the CrossCountry Contribution and Separation Agreement, CrossCountry and ENE will enter into a Transition Services Agreement pursuant to which ENE will provide to CrossCountry, on an interim, transitional basis, various services, including, but not limited to, the following categories of services: (i) office space and related services, (ii) information technology services, (iii) SAP accounting system usage rights and administrative support, (iv) tax services, (v) cash management services, (vi) insurance services, (vii) contract management and purchasing support services, (viii) corporate legal services, (ix) corporate secretary services, (x) off-site and on-site storage, (xi) payroll, employee benefits and administration services, and (xii) services from RAC on a defined project basis. CrossCountry will provide to ENE, on an interim, transitional basis, various services, including, but not limited to, the following categories of services: (i) floor space for servers and other information technology equipment, (ii) technical expertise and assistance, including, without limitation, pipeline integrity, safety, environmental and compliance, (iii) accounts payable support, and (iv) accounting services relating to businesses owned directly or indirectly by ETS immediately prior to closing.

The parties are expected to enter into a Transition Services Supplemental Agreement at the closing of the CrossCountry Contribution and Separation Agreement. Subject to the consent of the Creditors' Committee, the Transition Services Supplemental Agreement will more fully delineate the services provided within each category set forth in the Transition Services Agreement. The charges for such transition services will be cost based. Certain services will be charged on an "as needed" basis.

Provision of the transition services will commence on the effective date of the Transition Services Agreement and terminate on December 31, 2004, unless otherwise agreed in writing by the parties. However, except as otherwise provided for in the Transition Services Supplemental Agreement, ENE may terminate any transition service upon ninety days' prior written notice to CrossCountry.

(ii) Cross License Agreement. At the closing of the transactions contemplated by the CrossCountry Contribution and Separation Agreement, ENE and certain of its subsidiaries and affiliated companies will enter into a Cross License Agreement pursuant to which each of the companies that are a party to the Cross License Agreement will grant, without warranty of any kind, each and every other party and their respective subsidiaries, all of the intellectual property rights of the party granting the license in and to certain software programs, documentation, and patents described in the Cross License, a non-exclusive, royalty free, sublicensable license, with fully alienable rights, to (i) use, copy, and modify the licensed programs and documentation; (ii) use, make, have made, distribute, and sell any and all products and services of the party receiving the license as well as such party's subsidiaries and sublicensees (if any); and (iii) engage in the business of such party receiving the license and business of its subsidiaries and sublicensees (if any) prior to, on, and after the closing date.

The Cross License Agreement became will become effective on the closing date and the licenses granted will continue in perpetuity unless licenses granted to a breaching party are terminated by any affected non-breaching party in the event such breaching party fails to cure a material breach of the Cross License Agreement within thirty days after delivery of written notice of the breach.

(iii) Tax Sharing Agreement. At the closing of the transactions contemplated by the CrossCountry Contribution and Separation Agreement, CrossCountry, CrossCountry Citrus Corp., Northern Plains, Pan Border, NBP Services, Transwestern Holding, and Transwestern will enter into a Tax Sharing Agreement with ENE. The Tax Sharing Agreement will set forth the respective rights and responsibilities of the parties to the Tax Sharing Agreement with respect to taxes. Under the Tax Sharing Agreement, the parties will cause their respective subsidiaries to consent, to the extent necessary, to the filing of consolidated returns by ENE, including consolidated returns for the tax year ended December 31, 2003, and for each year thereafter that they are eligible to file consolidated returns, until such time as ENE, in the exercise of its sole discretion, elects to refrain from filing consolidated tax returns. ENE will be responsible for, among other things, the preparation and filing of all required consolidated returns on behalf of the companies and their subsidiaries, making elections and adopting accounting methods, filing claims for refund or credit, and managing audits and other administrative proceedings conducted by the IRS.

Under this agreement, CrossCountry and each subsidiary that is a member of the ENE Tax Group will be obligated to pay ENE the amount of income tax that it would have paid on a stand-alone basis and each of the parties and their respective subsidiaries will be compensated for the use of their respective net operating losses and/or tax credits to the extent utilized in the ENE consolidated return (other than the use of such losses or credits to offset gain in respect of an election pursuant to section 338(h)(10) of the IRC).

Prior to a subsidiary of ENE that is a party to the Tax Sharing Agreement ceasing to be a member of the ENE consolidated tax group, all intercompany payable accounts and intercompany receivable accounts of such subsidiary will be offset and netted against each other. If the resulting net balance is a payable from such subsidiary to ENE, then such subsidiary will pay the amount due to ENE. If the resulting net balance is a receivable from ENE to such subsidiary (other than Transwestern), then such subsidiary will assign and transfer its interest in the receivable to ENE. If the resulting net balance is a receivable from ENE to Transwestern, ENE and Transwestern will determine how such receivable will be settled.

The Tax Sharing Agreement will become effective on the closing date of the CrossCountry Contribution and Separation Agreement. After the Effective Date, ENE and

CrossCountry may continue to be parties to this Tax Sharing Agreement, or a new tax sharing agreement on similar terms until ENE and CrossCountry no longer file consolidated returns.

(iv) The Ardmore Collocation License Agreement. Prior to the closing of the CrossCountry Contribution and Separation Agreement, ENE and CrossCountry will enter into a license or lease agreement under which CrossCountry will lease to ENE adequate floor space in the Ardmore Data Center for servers and other information technology equipment owned by the CrossCountry Enron Parties. The space will be provided on a cost-basis for a term to be specified in the Ardmore Collocation License Agreement.

c. Implementation of CrossCountry Contribution and Separation Agreement

With the consent of the Creditors' Committee, the Debtors and their affiliates may seek to effect an election under Section 338(h)(10) of the IRC for CrossCountry, which would increase the basis, for federal income tax purposes, of certain assets of CrossCountry to their fair market values. Prior to making such election, the Debtors intend to seek a ruling from the IRS concerning the availability of this election; however, there is no assurance that a favorable ruling, if requested, will be obtained.

In order to qualify for this election, it is anticipated that the CrossCountry Equity Interests would be transferred by the CrossCountry Enron Parties to a limited liability company ("CrossCountry LLC"), subject to the rights of CrossCountry described below. The consideration for the CrossCountry Equity Interests would consist of membership interests in CrossCountry LLC. Thereafter, immediately prior to the distribution of CrossCountry Common Stock to applicable holders of Allowed Claims and the reserve for Disputed Claims, it is anticipated that CrossCountry LLC would convey the CrossCountry Equity Interests to CrossCountry pursuant to a merger, sale or other transaction. The consideration to be received by the CrossCountry Enron Parties, as members of CrossCountry LLC, in connection with such transaction would consist of (i) CrossCountry Common Stock and (ii) other consideration which may consist, in whole or in part, of non-voting, preferred stock (such preferred stock, if issued, will have a liquidation preference with a priority over the rights of holders of CrossCountry common stock). Such preferred stock will not be cancelled by operation of the Plan, but the ultimate disposition of such preferred stock has not been determined.

2. Certain Business Relationships

a. TGS. In 1992, Argentina granted TGS a 35-year license to operate Argentina's main natural gas pipeline. Following a competitive bid process, the Argentine government awarded the bid to own and operate the TGS pipeline to a consortium that included ENE. As part of the bid application, Transwestern agreed to provide ongoing technical support to the ENE affiliate, EPCA, serving as the Technical Operator for the TGS pipeline. In addition, Transwestern guaranteed the performance of Enron Pipeline Company of Argentina's obligations under certain shareholder and other agreements with its joint venture partner. The surviving performance obligations under these agreements primarily involve corporate governance issues and shareholder rights.

b. ENE. The businesses that will be contributed to CrossCountry upon closing of the formation transactions have in place a number of arrangements with ENE, its subsidiaries and affiliates for certain general corporate services, including, but not limited to, information technology related matters, benefits plans or benefits related matters, and tax sharing arrangements. Upon closing of the formation transactions, these services will be provided pursuant to the agreements described herein. In addition, various agreements exist that are associated with the services provided by the business to the subsidiaries and affiliates of ENE such as natural gas transportation agreements and agreements that relate to the operation of the businesses such as compression services agreements.

Contemporaneous with the initiation of the Chapter 11 Cases, ENE and a number of its subsidiaries and affiliates that are the subject of Chapter 11 Cases ceased performance of their respective obligations under a number of such agreements with one or more of the CrossCountry companies or third parties. Those agreements (as well as any other agreements entered into by one of CrossCountry's businesses with a Debtor) have been, or are subject to being, rejected, at the option of the Debtor, as executory contracts. ENE and those of its subsidiaries and affiliates involved in the Chapter 11 Cases have not yet identified the agreements that will be rejected as executory contracts. CrossCountry may assume certain obligations to pay prepetition amounts due under certain contracts that CrossCountry elects to be assigned to it by Debtor entities. CrossCountry is not able to currently quantify the amount of such costs.

Transwestern and Florida Gas have entered into compression services agreements with ECS, an ENE affiliate, that continues to perform under the terms of such agreements.

Transwestern and Citrus have entered into hedging and transportation arrangements and intercompany loans with ENE and/or its subsidiaries or affiliates. Resolution of any claims by or against Transwestern and Citrus relating to such transactions will be addressed in the Plan.

ENE and El Paso's subsidiary, Southern Natural Gas, are parties to a Capital Stock Agreement, which governs ownership and disposition of the shares of Citrus. On October 31, 2003, ENE filed with the Bankruptcy Court, under a notice of presentment, a motion for an order approving assumption and assignment of the Capital Stock Agreement to CrossCountry or its designee. Following assumption and assignment, CrossCountry or its designee will become the Principal under the Capital Stock Agreement. The deadline for filing objections to the motion is November 17, 2003. A hearing will be held on November 20, 2003 to consider the motion. If the motion is approved, ENE will be relieved from any obligations under the Capital Stock Agreement in accordance with section 365 of the Bankruptcy Code. If the motion is denied, EL Paso's consent may be required for distribution of CrossCountry Common Stock pursuant to the terms of the Plan or if CrossCountry is to be sold to a third party, to the extent the Capital Stock Agreement remains binding on ENE. Refer to Section XIV.A.4, "Delayed Distribution or Non-Distribution of Plan Securities" for further information.

Northern Border Partners and its subsidiaries have entered into various agreements with ENE and certain affiliates that are subject to the bankruptcy proceedings that are described in Northern Border Partners' annual report on Form 10-K for the year ended

December 31, 2002, which report was not prepared by the Debtors but may contain information relevant to the Creditors' decision to approve the Plan.

G. Indemnification of Directors and Officers

CrossCountry's certificate of incorporation provides that CrossCountry will indemnify directors and officers of CrossCountry to the fullest extent permitted by the Delaware General Corporation Law for actions taken in their capacity as directors and officers of CrossCountry. Expenses incurred by a director or officer in connection with an indemnifiable claim will be addressed by CrossCountry provided that such director or officer will be obligated to repay such advance to the extent it is ultimately determined that such director or officer was not entitled to indemnification. CrossCountry is authorized, in its discretion, to provide the same indemnification protections to employees and agents.

Under Delaware law, directors, officers, employees and other individuals may be indemnified against expenses (including attorneys' fees), judgments, fines, and amounts paid in settlement in connection with specified actions, suits or proceedings, whether civil, criminal, administrative or investigative (a derivative action) if they acted in good faith and in a manner they reasonably believed to be in or not opposed to the best interests of CrossCountry and, with respect to any criminal action or proceeding, had no reasonable cause to believe their conduct was unlawful. A similar standard of care is applicable in the case of a derivative action, except that indemnification only extends to expenses (including attorneys' fees) incurred in connection with defense or settlement of such an action and Delaware law requires court approval before there can be any indemnification of expenses where the person seeking indemnification has been found liable to CrossCountry.

H. Equity Compensation Plan

Following confirmation of the Plan, in order to attract, retain and motivate highly competent persons as key employees and/or directors of CrossCountry, CrossCountry expects to adopt a long-term equity incentive compensation plan providing for awards to such individuals. It is anticipated that the Compensation Committee of CrossCountry's Board of Directors will determine the specific terms of any grants made under such plan and will provide grants of awards designed to focus equity compensation on performance and alignment with shareholders interests; provided, however, that shares reserved for the plan will not exceed 10% of the CrossCountry Common Stock to be issued pursuant to the Plan, with projected annual share usage under the plan not exceeding 2%.

X. Prisma Energy International Inc.

Capitalized terms used throughout this Disclosure Statement are defined in Appendix A: "Material Defined Terms for Enron Disclosure Statement" attached hereto.

A. Business

1. General

Prisma is a Cayman Islands exempted company with limited liability formed to own and, in certain circumstances, operate many of ENE's international energy infrastructure businesses. No operating businesses or assets have been transferred to Prisma at this time; however, subject to obtaining requisite consents, the Debtors intend to transfer the businesses described in this section of the Disclosure Statement to Prisma either in connection with the Plan or at such earlier date as may be determined by ENE and approved by the Bankruptcy Court. In addition, as previously approved by the Bankruptcy Court, the Debtors have transferred certain employees to a wholly-owned subsidiary of Prisma formed to provide services to Prisma and its subsidiaries, as well as, in certain instances, the Debtors and their affiliates, with respect to operating and managing international assets.

The Debtors are actively pursuing a strategy to obtain the requisite consents, including approval of the Bankruptcy Court, in order to transfer certain operating businesses and assets to Prisma and its subsidiaries; however, there can be no assurance as to which businesses and assets ultimately will comprise Prisma. Prisma will be engaged in the generation and distribution of electricity, the transportation and distribution of natural gas and LPG, and the processing of NGLs. If all businesses are transferred to Prisma as contemplated, Prisma will own interests in businesses whose assets will:

- include over 9,600 miles of natural gas transmission and distribution pipelines;
- include over 56,000 miles of electric transmission and distribution lines;
- include over 2,100 MW of electric generating capacity;
- serve 6.5 million LPG, gas, and electricity customers;
- be located in 14 countries; and
- employ over 7,900 people.

Prisma will be an energy infrastructure company providing energy generation, transportation, processing, and distribution services in a safe and reliable manner. By concentrating on its core competencies of owning and operating energy infrastructure assets in diverse international locations, Prisma intends to focus on being a low-cost, efficient operator in the markets it serves. Prisma's anticipated objective is to generate stable cash flow, earnings per share, and dividends, and to grow each of these through growth projected within the existing portfolio of businesses. Prisma will operate through three business segments—Natural Gas Services, Power Distribution, and Power Generation. Prisma should be well-positioned to implement its planned strategy, but it will face risks both specific to its assets and general to the markets and countries in which it will operate. In addition to Bankruptcy Court approval, the transfer of the businesses described in this Disclosure Statement to Prisma will require the consent of other parties, including, but not limited to, governmental authorities in various jurisdictions. If any such consents are not obtained, then at the discretion of ENE, with the consent of the Creditors' Committee, as contemplated in the Plan, one or more of these businesses may not be transferred to Prisma, but instead will remain directly or indirectly with ENE. Refer to Section X.A.2., "Risk Factors" for further information.

The corporate affairs of Prisma will be governed by its memorandum and articles of association, amended and restated versions of which will accompany the Prisma Contribution and Separation Agreement, and by the Companies Law and common law in the Cayman Islands. The rights of shareholders and the fiduciary responsibilities of directors under Cayman Islands law are not as clearly established as under statutes or judicial precedent in existence in jurisdictions in the United States. For example, unlike in many jurisdictions in the United States, Cayman Islands law does not specifically provide for shareholder appraisal rights on a merger or consolidation of a company. Shareholders of Cayman Islands exempted companies have no general rights under Cayman Islands law to obtain copies of lists of shareholders of the company or to inspect its corporate records or accounts except as may be permitted under the Articles of Association. Subject to limited exceptions, under Cayman Islands law, a minority shareholder may not bring a derivative action against the board of directors. There are other differences between Cayman Islands and U.S. corporate law not summarized here. Also, because Prisma is a Cayman Islands exempted company, there is uncertainty as to whether the Grand Court of the Cayman Islands would recognize or enforce judgments of United States courts obtained against Prisma predicated upon the civil liability provisions of the securities laws of the United States or any state thereof to the extent such provisions constitute a fine or similar penalty, or be competent to hear original actions brought in the Cayman Islands against Prisma predicated upon the securities law of the United States or any state thereof.

a. Natural Gas Services. Natural Gas Services is expected to serve its customers through natural gas and liquids pipelines, natural gas and LPG distribution systems, LPG import terminals, and natural gas processing facilities. Generally, the assets planned to be a part of Natural Gas Services are either subject to firm contracts for their capacity (*i.e.*, long-term transportation or processing contracts designed to provide a fixed customer fee regardless of the level of actual throughput) or are regulated and have historically provided a stable, predictable stream of cash flows. Refer to Section X.A.2., "Risk Factors" for further information on conditions and developments that could upset this stability. By utilizing and building on its initial infrastructure, Natural Gas Services will strive to capture additional throughput volumes or connect to incremental customers and, therefore, generate additional cash flows.

Specifically, Natural Gas Services is expected to consist of ownership interests in:

- nine city gas distribution companies located in South Korea providing service to over two million customers;

- LPG distribution businesses located in Venezuela and South Korea providing service, directly or through distributors, to over 2.2 million customers;

- six separate transportation businesses located in South America with a daily throughput capacity of approximately 3.2 billion cubic feet per day of natural gas spanning more than 6,000 miles; and

- NGL extraction, fractionation, refrigeration, and storage facilities located in Venezuela.

b. Power Distribution. It is anticipated that Power Distribution will provide retail electricity delivery to approximately 1.8 million customers in the States of São Paulo and Mato Grosso do Sul, Brazil, through subsidiary Elektro, a Brazilian local electricity distribution company. Prisma is expected to own 99.62% of Elektro.

Elektro's concession area covers 223 municipalities in São Paulo and five municipalities in Mato Grosso do Sul, encompassing approximately 56,000 miles of distribution lines. A 30-year renewable concession contract, the first term of which expires in 2028, provides exclusive distribution rights within the concession area. Elektro is a business that has historically provided a stable, predictable local currency cash flow stream with moderate growth.

São Paulo, located in the southeastern region of the country, is the most highly urbanized and industrialized state in Brazil. Its economy accounts for approximately 37% of Brazilian GDP and 33% of national electricity consumption. Elektro is the third-largest local electricity distribution company in São Paulo and the seventh-largest in Brazil.

In the period from 1990 to 2000, the overall electricity consumption in Brazil increased by a 4.4% CAGR. During the same period the electricity consumption in Elektro's concession area grew at a CAGR of 5.1%, exceeding average consumption in the southeastern region.

c. Power Generation. Power Generation is expected to consist of ownership interests in ten power plants. These power plants:

- have a total generating capacity of approximately 2,100 MW, with Prisma's ownership percentage representing generating capacity of approximately 1,180 MW;
- are located in Argentina, Brazil, the Dominican Republic, Guam, Guatemala, Nicaragua, Panama, the Philippines, Poland, and Turkey; and
- utilize natural gas as the primary fuel in four plants, and liquid fuel in the remainder.

It is anticipated that Power Generation will generate stable cash flows as most of the electrical capacity and energy of the power plants has been pre-sold on a long-term basis to cover all fixed and variable costs of operations, fuel costs and debt service and a return on equity capital. To the extent any generating capacity remains uncommitted, Prisma is expected to market such excess generation into available markets. Approximately 85% to 90% of the expected generating capacity of Prisma in 2003 and over the succeeding three years is fully contracted.

2. Risk Factors

Refer to Section XIV., "Risk Factors and Other Factors to be Considered" for further information related to the risks applicable to Prisma. The risks described therein are not the only ones facing Prisma. Additional risks are also described in the individual descriptions of the businesses expected to be a part of Prisma. Other risks may not presently be known to ENE or ENE may have deemed them to be immaterial at this time. Prisma's businesses, financial condition, and results of operations could be materially adversely affected by any of these risks.

Prisma has been formed, but no operating businesses or assets have been transferred to Prisma at this time. The Debtors and Prisma are currently seeking numerous approvals, consents, and waivers from lenders, partners, governmental authorities, and other parties to allow the businesses described in this Disclosure Statement to be transferred to Prisma in connection with the Plan. There can be no assurance that all or any of such approvals or consents can be obtained. Certain of the approvals and consents are required pursuant to applicable agreements or law to be obtained prior to the initial transfer of the businesses to Prisma and others will be triggered upon the distribution of shares of Prisma's capital stock pursuant to the Plan. Nevertheless, the Debtors and Prisma are seeking consents for both the initial transfer and the subsequent distribution of shares to the creditors prior to the initial transfer of each business to Prisma. In addition, the Debtors and Prisma are seeking the consent of certain parties to any post-transfer sale of Prisma or discrete businesses within Prisma to as of yet unidentified third parties. There can be no assurance, however, that these consents will be obtained. The required consents and approvals generally fall into the following categories:

- *Lenders*. The many credit facilities and other debt instruments to which the businesses to be transferred to Prisma are parties often require ENE to directly or indirectly hold specified percentages of the equity interests in the business, or provide that a change of control of the business is an event of default. The lenders, including various multilateral agencies, under these credit facilities and other debt instruments must therefore consent to ENE no longer being in the chain of ownership of the transferred businesses.

- *Governmental Authorities*. Many of the businesses to be transferred to Prisma are regulated by local energy regulatory authorities, operate pursuant to concessions granted by governmental authorities or are party to agreements with governmental authorities. These regulatory and other governmental authorities often must consent to the transfer of the businesses to Prisma. Additionally, certain of the proposed transfers to Prisma are subject to review by antitrust agencies, which either must approve the transfer in advance or have the authority to impose conditions on Prisma's business following the transfer.

- *Partners*. Because ENE and its subsidiaries generally own less than 100% of the businesses to be transferred to Prisma, they are sometimes party to shareholder agreements that, among other things, require the shareholders to consent to certain transfers by a shareholder of its equity interest in the business to a third party or give the shareholders preferential purchase rights in connection with certain transfers of equity interests in the business. The preferential rights often include (1) rights of first refusal that require a party to offer to sell its equity interests to the other shareholders on the same or more favorable terms on which it would be willing to sell its equity to a third party and (2) change of control purchase rights that require a shareholder that has experienced a direct or indirect change of control to offer to sell its equity interest in the business to the other shareholders. To the extent that these purchase rights are applicable to the transfer of businesses to Prisma or the subsequent distribution of shares of Prisma's capital stock, ENE expects to either offer these purchase rights to the other shareholders or ask the shareholders to waive their rights prior to the transfer to Prisma.

- *Debtors' Financing Structures — Rawhide*. Refer to Section III.F.42, "Rawhide" for information regarding the financing transaction referred to as Rawhide. ENE, with Ponderosa, indirectly owns 50% of Centragas, which interests are expected to be transferred to Prisma. The transfer of these interests to Prisma may be subject to the consent of the holders of the debt and equity interests in this financing structure, which may or may not be granted in connection with an overall settlement of the various rights and obligations between ENE and the financing structure. No assurances can be given that the Debtors and Prisma will obtain the requisite structure related consents and approvals (if any) required to transfer Centragas into Prisma.

- *Debtors' Financing Structures — Osprey/Whitewing*. Refer to Section III.F.41, "Osprey/Whitewing" for information regarding the financing transaction referred to as Osprey/Whitewing. Including any interests in which Osprey may assert a beneficial interest, ENE indirectly owns 99.62% of Elektro, 100% of ENS and 50% of Trakya, which interests are expected to be transferred to Prisma. The transfer of these interests to Prisma may be subject to the consent of the holders of the debt and equity interests in this financing structure, which may or may not be granted in connection with an overall settlement of the various rights and obligations between ENE and the financing structure. No assurances can be given that the Debtors and Prisma will obtain the requisite structure related consents and approvals (if any) required to transfer Elektro, ENS and/or Trakya into Prisma.

- *Debtors' Financing Structures — Enron Equity Corp*. Refer to Section III.F.21, "Enron Equity Corp." for information regarding the financing transaction referred to as Enron Equity Corp. Including any interests in which Enron Equity Corp. may assert a beneficial interest, ENE, with Ponderosa, indirectly owns 50% of Centragas and ENE indirectly owns 85% of SECLP. The entities transferring these assets to Prisma are Debtors (including Enron Holding Company LLC and Enron Commercial Finance Ltd.) and, at this time, it is anticipated that these Debtors will not make any distributions to their equity holders. In addition, Enron Equity Corp. holds an indirect 0.89% interest in SECLP which is not being transferred into Prisma.

If any required approval, consent or waiver relating to the transfer of a particular business or the subsequent distribution of shares to the creditors cannot be obtained prior to the transfer of the assets to Prisma, then at the discretion of ENE, with the consent of the Creditors' Committee, as contemplated in the Plan, such business may not be transferred to Prisma and, instead, would remain, directly or indirectly, with ENE. Refer to Section X.A.3., "Transferred Businesses" for further information about businesses that would remain with ENE. As a result, it is possible that Prisma's businesses may not include all of the transferred businesses described in this Disclosure Statement. In addition, it is possible that any consents or approvals that are given could contain conditions or limitations that could adversely affect Prisma's ability to operate and manage its business, or adversely affect its financial results.

Following the transfers to Prisma, certain businesses will remain subject to governmental rules and regulations, such as utility ownership requirements or antitrust laws, which may require that an approval be obtained each time there is a direct or indirect change in the ownership or control of such business. The failure to obtain such an approval may result in violations of local laws, the loss of governmental approvals, and defaults under applicable loan agreements. Such approval requirements could deter changes in ownership or control of Prisma that may otherwise have occurred, and any actual change in the ownership or control of Prisma that would trigger any such approval requirements could adversely impact the price and liquidity of the shares of stock of Prisma.

3. Transferred Businesses

a. Worldwide Asset Base. All of the businesses that are expected to be a part of Prisma are located outside the United States, except for one business located in the U.S. territory of Guam. Prisma will face different political, economic, and regulatory challenges in each of the 14 countries in which it will operate. While operating in several countries will bring many challenges, it should also help Prisma to diversify its risks and create additional expansion opportunities. Refer to Section XIV.I.1.b., "Regulatory Intervention and Political Pressure" for further information.

b. Formation of Prisma and Contribution of Prisma Assets

Prisma was organized as an exempted company with limited liability in the Cayman Islands on June 24, 2003 for the purpose of acquiring the Prisma Assets, which include equity interests in the identified businesses, intercompany loans to the businesses held by affiliates of ENE, and contractual rights held by affiliates of ENE. ENE and its affiliates will contribute the Prisma Assets to Prisma in exchange for shares of Prisma Common Stock commensurate with the value of the Prisma Assets contributed. The contribution of the Prisma Assets is expected to be effected pursuant to a Prisma Contribution and Separation Agreement to be entered into among Prisma and ENE and several of its affiliates. It is anticipated that the Prisma Contribution and Separation Agreement, which is currently being negotiated, will be submitted for Bankruptcy Court approval either as part of the Plan Supplement or by a separate motion. Refer to Section X.E., "Prisma Contribution and Separation Agreement" for additional information. Prisma and ENE and its affiliates also expect to enter into certain ancillary agreements, which may include a new Transition Services Agreement, a Tax Allocation Agreement and a Cross License Agreement.

The employees of ENE and its affiliates who have been supervising and managing the Prisma Assets since December 2001, became employees of a subsidiary of Prisma effective on or about July 31, 2003. In connection therewith, as approved by the Bankruptcy Court, ENE and its affiliates entered into four separate Transition Services Agreements pursuant to which such employees will continue to supervise and manage the Prisma Assets and other international assets and interests owned or operated by ENE and its affiliates.

The ancillary agreements, together with the Prisma Contribution and Separation Agreement, will govern the relationship between Prisma and ENE and its affiliates subsequent to the contribution of the Prisma Assets, provide for the performance of certain interim services, and define other rights and obligations until the distribution of shares of capital stock of Prisma pursuant to the Plan or the sale of the stock to a third party. In addition, the Prisma Contribution and Separation Agreement or the ancillary agreements are expected to set forth certain shareholder protection provisions with respect to Prisma and may contain indemnification obligations of the Prisma Enron Parties.

c. Natural Gas Services. The tables below identify the non-pipeline and pipeline businesses included in the Natural Gas Services segment and several of their key features.

Natural Gas Services Non-Pipeline Businesses

Business	Location	Anticipated Prisma Ownership Interest	Business	Date Commercial Operation Was Initiated	Scheduled Termination Date of Key Project Agreement
SK-Enron	South Korea	50.0%	Holding company for equity interests in nine CGCs, two gas facility construction and sale companies, one LPG import and marketing company and one cogeneration company	July 1978 to February 1990 (depending on business)	Not applicable
Cuiabá – TBS	Bolivia and Argentina	50.0%	Purchase and sale of natural gas for Cuiabá-EPE	May 2002	May 4, 2019
Vengas	Venezuela	97.0%	Propane transporter and distributor	1953	Not applicable

Business	Location	Anticipated Prisma Ownership Interest	Business	Date Commercial Operation Was Initiated	Scheduled Termination Date of Key Project Agreement
Accroven	Venezuela	49.25%	NGL extraction, fractionation, refrigeration and storage facilities	July 10, 2001	July 9, 2021

Natural Gas Services Pipelines

Business	Location	Anticipated Prisma Ownership Interest	Route Length and Transport Capacity	Business	Date Commercial Operation Was Initiated	Scheduled Termination Date of Principal Transportation Agreements
Cuiabá – GasBol	Bolivia	50.0%	Bolivian portion of the BBPL to Bolivia-Brazil border at San Matias, 226 miles, current capacity of 95 MMcf/d	Natural gas pipeline	May 2002	November 24, 2024
Cuiabá – GasMat	Brazil	50.0%	Bolivia-Brazil border at San Matias to EPE power plant, 175 miles, current capacity of 95 MMcf/d	Natural gas pipeline	May 2002	June 4, 2024
Transredes	Bolivia	25.0%	A network of pipelines in Bolivia with connections to Brazil, Argentina and Chile, approximately 1,800 miles of gas pipeline, 1,700 miles of liquids pipeline	Natural gas and liquids pipeline network	May 1997 (formation)	2003 to 2019
BBPL – GTB	Bolivia	17.0% and 12.75% through its partial ownership of Transredes	Rio Grande to Mutun, approximately 350 miles, current capacity of approximately 1.1 bcf/d	Natural gas pipeline	July 1999	TCQ 2021 TCX 2021 TCO 2041
BBPL – TBG	Brazil	4.0% and 3% through its partial ownership of Transredes	Corumbá to Porto Alegre, approximately 1,600 miles, nominal capacity of 30 MMcm/d of gas	Natural gas pipeline	July 1999	TCQ 2021 TCX 2021 TCO 2041
Centragas	Colombia	50.0%	Ballena to Barrancabermeja, 359 miles, maximum capacity of 200 MMcf/d	Natural gas pipeline	February 24, 1996	February 24, 2011

As indicated above, each of the Natural Gas Services businesses that is expected to be included in Prisma has been completed and has initiated commercial operations.

(i) SK-Enron Co., Ltd. (SK-Enron). ENE indirectly owns 50% of the outstanding shares of SK-Enron. The other 50% of SK-Enron's outstanding shares are owned by SK, which in 2002 was the third-largest business group, or *chaebol*, in South Korea. SK-Enron is a holding company for 100% of the outstanding shares of seven privately held CGCs and a cogeneration company in South Korea, as well as leading or controlling stakes in two publicly traded CGCs and an LPG importing and marketing company in South Korea. In addition, each of the two publicly traded CGCs has a subsidiary company that is engaged in the construction of gas facilities and sale of gas equipment. Under its holding company structure, SK-Enron conducts substantially all of its LPG and natural gas delivery operations through its subsidiaries and controlled affiliates and provides primarily shared support services through the holding company.

SK-Enron's affiliates operate in three businesses: (1) city gas distribution, which represented 52% of SK-Enron's 2002 revenues under Korean GAAP accounting (which consolidates the revenues of all subsidiaries in which the parent company has at least a 30% ownership interest); (2) LPG import and marketing, which represented 47% of SK-Enron's 2002 revenues under Korean GAAP accounting; and (3) cogeneration.

(A) City Gas. Each of SK-Enron's nine CGCs is a publicly-regulated utility with an exclusive franchise to engage in the distribution of natural gas (and in one case, a mixture of LPG and air) to retail, commercial, and industrial customers in its respective franchise area, with certain limited exceptions. To this end, each of SK-Enron's CGCs owns distribution pipelines for transporting natural gas from the national trunk pipeline transmission system owned by KOGAS, the national monopoly natural gas wholesaling company, to the CGC's customers. Under the South Korean regulatory structure, CGCs operate on a regulated rate of return basis. The prices at which CGCs purchase gas are set by KOGAS and approved by the South Korean Ministry of Commerce, Industry and Energy, while local regulatory authorities set the tariffs for retail gas distribution. Regulated retail tariffs are designed to include full pass-throughs of fuel, operating, and capital costs plus a regulated rate of return on investment.

(B) LPG. SK-Enron's subsidiary, SK Gas, is one of the two leading LPG importing and marketing companies operating in South Korea and supplied approximately 25% of domestic LPG consumption by volume in 2002. Approximately 57% of SK Gas's 2002 revenue was generated through the retail sale of LPG to refineries, industrial customers, and petrochemical companies and through wholesale sales to CGCs and other retailers. The balance of its 2002 revenue was generated through LPG trading activities. SK Gas owns and operates two large LPG receiving terminals and one of the world's largest single underground storage rock caverns.

(C) Cogeneration. Iksan Energy owns a 20-MW coal-fired cogeneration facility which serves 32 steam offtakers and supplies power to Korea Electric Power Company, the national power company of South Korea.

(D) City Gas Distribution. South Korea currently has a total of 32 CGCs. SK-Enron is the largest gas distribution business in South Korea. The nine CGCs affiliated with SK-Enron supplied approximately 25% of total domestic city gas demand in 2002, providing service to over two million customers. The SK-Enron CGCs provide service to all or a portion of three of the four largest cities in South Korea. The customer mix is split among residential, industrial, and commercial and varies among the individual CGCs. Historically, however, the higher margin residential segment has comprised approximately 50% of total volume. The SK-Enron CGCs purchase all of their supplies of gas from KOGAS as regassified LNG for delivery by pipeline pursuant to long-term contracts. In certain of the jurisdictions in which the SK-Enron CGCs operate, the CGCs are subject to local government regulations that require them to provide gas supply to customers upon request. However, these requirements are subject to a number of broad exceptions, including force majeure, technical difficulty in providing connections and faulty supply facilities. As a result, SK-Enron CGCs are largely exempt from liabilities to customers in their franchise areas for failure to provide service under these circumstances.

(E) Industry Overview. South Korean natural gas demand is split between the electricity sector (33% of total volume in 2002) and the city gas sector (67% of total volume in 2002). South Korea currently relies on imported LNG to meet its entire demand for natural gas. Residential customers are the largest consumers of CGC-delivered natural gas, comprising approximately 60% of total volume in 2002. Due to higher gross tariffs applied to residential customers based on a uniform cost of gas, residential customers provide higher profit margins than industrial, commercial, or other customers. The total number of households supplied with natural gas by CGCs has increased from 6.5 million households in 1998 to 9.4 million in 2002 and is forecasted by the Korean City Gas Association to increase to almost 10.6 million by 2004. LPG consumption in 2002 was divided among household and commercial activities (32%), petrochemical and industrial activities (21%), transportation fuels (45%), and city gas (2%). LPG is growing in importance in South Korea as a transportation fuel, the largest sector usage.

(F) Shareholder Arrangements. When SK-Enron was formed in 1999, SK and Enron Korea entered into a Shareholders Agreement that defines, among other things, certain rights of first refusal, buy-sell rights, and consent rights to transfer by each shareholder, which by their terms do not apply in connection with upstream transfers such as the transfer of ENE's interests to Prisma. The Shareholders Agreement provides, among other things, that the Board of Directors is split equally between SK and Enron Korea nominees, certain executive positions rotate periodically between SK and Enron Korea nominees, and certain SK-Enron actions require prior board approval. The Shareholders Agreement governs the treatment of certain business activities and opportunities and provides, subject to certain exceptions, that neither shareholder nor its affiliates may pursue any of SK-Enron's primary business activities outside of SK-Enron without the other shareholder's consent. Restrictions also apply to certain other business opportunities.

(G) Dividends. Although its organizational documents do not prohibit dividends, SK-Enron's Shareholders Agreement expresses a preference to minimize dividends unless the parties otherwise agree. Historically SK-Enron has reinvested its earnings, and its Board of Directors has not declared any dividends.

(H) Shareholder Disputes. In connection with a dispute between SK and Enron Korea over certain matters, including alleged activities resulting in the failure of a proposed sale by Enron Korea of its interests in SK-Enron to close in 2002 and the subsequent abandonment of the transaction by the potential buyer, Enron Korea sent a prearbitration notice to SK under the Shareholders Agreement. SK and Enron Korea have not proceeded further with the arbitration process. SK previously obtained an order from a South Korean court permitting SK to place a "preliminary attachment" lien on Enron Korea's shares in SK-Enron to secure certain claims, and although the period for enforcement of the lien has lapsed, there can be no assurance that SK will not again seek to place a lien on Enron Korea's shares in SK-Enron. Refer to Section XIV.I.1.f., "Difficulty Enforcing and Defending Contractual and Legal Rights" for further information. In any event, a lien on Enron Korea's shares of SK-Enron would not affect ENE's ability to transfer its interest in SK-Enron to Prisma.

(I) SK Issues. As a result of investigations into certain business activities by the Seoul District Public Prosecutors, accounting irregularities were reportedly discovered in early 2003 at one of SK's affiliates, SK Networks (formerly SK Global), which engages in worldwide trading operations on behalf of members of the SK group. As a result of this disclosure, SK Networks has been placed under a bank-supervised workout program, and SK Networks' U.S. subsidiary filed for bankruptcy protection in the U.S. in July 2003. SK Networks' main creditor banks requested that the stronger units of the SK group, including SK, provide financial support to SK Networks. These events were accompanied by reported reductions in bank lines of credit to SK group companies by banks and investment trust companies, and led to a decision by S&P Rating Services to lower its long-term credit rating on SK in May 2003. There can be no assurance that SK will not suffer further deteriorations in its credit rating. In September 2003, the creditors of SK Networks agreed on a debt restructuring scheme for the company which involves, among other things, conversion of a substantial amount of its debt held by SK into equity of SK Networks, which SK Corp. agreed to in October 2003. In addition, news articles have indicated that SK Shipping, another affiliate of SK, may also face financial difficulties due to alleged accounting irregularities. None of the ongoing investigations or debt restructuring involves SK-Enron or Enron Korea, and SK-Enron and its operations have not been significantly affected by these events to date. However, no assurances can be given that the issues surrounding SK will not adversely affect SK-Enron in the future.

(J) Associated Debt. SK-Enron has financed, and currently expects to continue to finance, its and its subsidiaries' ongoing operations and any subsequent acquisitions primarily from cash flows. SK Gas incurred a substantial amount of secured term debt in connection with the construction of certain storage and processing facilities, with liens securing that debt equal to approximately 48% of the total book value of the underlying SK Gas assets as of December 31, 2002.

(K) Property, Plant and Equipment. Each of the SK-Enron CGCs owns a network of lateral pipelines connecting to KOGAS transmission lines, distribution pipelines, and related facilities for distributing gas to its customers. The SK-Enron CGCs own altogether a total of approximately 5,600 kilometers of pipe. SK Gas owns two LPG receiving terminals that serve as domestic import and distribution hubs and as loading facilities for transferring cargos from large ocean-going ships to smaller coastal trading ships. Iksan Energy owns a coal-fired cogeneration facility, which serves 32 steam offtakers and supplies power to Korea Electric Power Company. SK-Enron and its subsidiaries also own or lease offices for their operations for varying periods.

(L) Competition. Although the geographic franchise grants to CGCs are exclusive, some competition exists in certain CGC territories from government-supported local district heating companies. Service areas in which local district heating companies operate are significantly less profitable for SK-Enron CGCs. CGCs provide gas solely for cooking in such areas instead of gas for cooking and heating, but with similar capital investment in distribution. In areas being served by local district heating companies, informal political pressure has occasionally been brought to bear on SK-Enron CGCs to provide cooking gas service at a loss. Although SK-Enron CGCs historically have been able to avoid being required to provide services under these circumstances, no assurance can be given that they will be able to continue to do so. SK-Enron CGCs might therefore be compelled to provide cooking gas services in the future at a loss, which could be material. Refer to Section XIV.I.1.b., "Regulatory Intervention and Political Pressure" for further information.

LPG is more expensive than natural gas on an equivalent BTU basis in locations served by natural gas, but serves as an alternative to natural gas in rural and suburban areas where natural gas is unavailable or portability of product is required. Historically, the expansion of natural gas into traditional LPG markets has been inhibited by the capital costs required to expand pipeline and retail distribution systems. The LPG import, distribution, and marketing sector has significant barriers to entry, due primarily to the cost of investment in storage.

(M) Regulation. South Korea currently relies on imported LNG to meet its entire demand for natural gas. At present, KOGAS controls all importation of LNG. As a general matter, domestic prices for wholesale gas sales to CGCs are set by KOGAS every two months, subject to review and approval by the South Korean Ministry of Commerce, Industry and Energy. Those CGCs that are not connected to the national trunk pipeline system rely on LPG supplied by SK Gas and other LPG wholesalers, which is then vaporized, mixed with air, and delivered to customers.

The South Korean Ministry of Commerce, Industry and Energy announced a gas industry restructuring plan in 1999 that is designed to result in wholesale and retail market competition, open access distribution systems, and customer choice of gas supplier. Although gas industry restructuring has been delayed, and certain early deadlines have already been missed, this proposal remains the current government plan for gas industry restructuring in South Korea. Transportation of gas is expected to be regulated under an "open access" scheme in which independent gas transporters would have the right to use the existing gas pipeline system upon payment of regulated tariffs, while pipeline system owners, which include the CGCs, would be protected from competition in transportation.

The South Korean Ministry of Commerce, Industry and Energy regulates the CGCs by regulating the operating costs that are recoverable from their customers and by providing guidelines for "proper margins" between wholesale and retail. These regulations are interpreted and implemented by the respective provincial tariff-setting authorities, which conduct annual tariff reviews for each CGC. The CGCs are generally permitted to pass-through KOGAS charges, which are the largest component of the tariff. Historically, a lack of specificity in the national regulations concerning tariff calculation methodologies has left considerable room for negotiation of rates with the provincial regulatory authorities, and many of these determinations have been very political and heavily negotiated. However, since 2001 the scope for negotiation of rates at the provincial level has been more limited due to the promulgation of more restrictive guidelines for such negotiations by the South Korean Ministry of Commerce, Industry and Energy. Refer to Section XIV.I.1.b., "Regulatory Intervention and Political Pressure" for further information.

In 2001, South Korea deregulated the LPG marketing and import business. SK Gas operates in the unregulated wholesale LPG market and is not subject to regulated tariffs. SK Gas supplied about 25% of total LPG demand in South Korea in 2002. Iksan Energy sells steam under contract to its offtakers, but electricity sales to Korea Electric Power Company are at the regulated market clearing price.

(N) Relations with Affiliates. SK Gas sells a substantial amount of LPG to SK, and SK Gas has historically carried an outstanding receivable of approximately $30 million from SK and certain of its affiliates other than SK-Enron and its subsidiaries. In addition, SK Gas has contracted with SK Shipping, an SK affiliate that reportedly may face financial difficulties, to supply substantially all of SK Gas's long-term LPG shipping capacity needs. If SK Shipping is unable to provide transport services for SK Gas, SK Gas would be required to replace such capacity with shipping contracts with third parties. There can be no assurance that SK Gas would be able to replace any or all of such capacity in a timely manner at rates and on other terms as favorable to SK Gas as its current contracts with SK Shipping.

(O) Holding Company Status & Taxation of Dividends. SK-Enron is structured as a holding company to take advantage of recent changes in South Korean law that facilitate the ability of members of a corporate group to pay dividends within the group. Prior to the enactment of these laws, the *chaebols* avoided holding company structures and dividends to move cash between group companies, loaning cash to related parties instead. However, the specified proportions of dividends received from subsidiaries of a company are now permitted to be excluded from the receiving company's income, subject to certain limitations. Due to certain cross-holdings among its subsidiaries and certain outstanding debt obligations of SK-Enron incurred in connection with acquisition of some of its subsidiaries, SK-Enron currently loses approximately 12% of the available dividend exclusion.

(ii) Transborder Gas Services, Ltd. (Cuiabá – TBS). Refer to Section X.A.3.e(i), "Cuiabá Integrated Project" for further information.

(iii) Vengas, S.A. (Vengas). Vengas is the largest distributor of LPG in Venezuela and has been in operation since 1953. Vengas has approximately 2,000 full-time employees, a substantial majority of whom are unionized. Vengas believes it serves an estimated 40% of the Venezuelan LPG market by volume, mostly through the distribution of Vengas brand LPG directly to approximately 2.2 million customers and through 85 sub-distributors and the remaining through sales of non-Vengas brand LPG through other channels. Vengas's direct customers include a network of approximately 7,500 "rack dealers" that sell LPG in small cylinders to an even greater number of individual customers.

Vengas's sole supplier of LPG is PdVSA at rates that are regulated by the Ministry of Energy and Mines. PdVSA is Venezuela's sole producer of LPG. Sales by Vengas to its residential customers, which represent approximately 90% of its sales, are also regulated by the Ministry of Energy and Mines. Vengas's costs and sales revenues are all in Venezuelan bolivars. Vengas has no long-term debt.

Vengas also owns a 99.19% interest in CALIFE, a Venezuelan utility. CALIFE distributes electric power to approximately 50,000 customers in the Venezuelan municipalities of Puerto Cabello and Morón and surrounding areas, with total electricity sales of 336 GWh in 2002. Vengas is seeking an orderly exit from CALIFE and the electricity distribution business because it is non-core to Vengas's LPG business and has historically suffered losses.

Vengas is 97% owned by ENE through its indirect subsidiary V. Holdings. The remaining 3% of the outstanding shares have been publicly held and traded on the Caracas Stock Exchange since 1993. ENE, through V. Holdings, controls the Board of Directors of Vengas. Dividends are approved by Vengas's shareholders on a yearly basis after receipt of audited financial statements prepared in accordance with Venezuelan GAAP. Since Vengas is listed on the Caracas Stock Exchange, it is required by Venezuelan law to declare at least 50% of its net earnings after income taxes and legal reserves as dividends and to pay at least 25% of this amount in cash. V. Holdings also owns 100% interests in Java and Finven. Finven was created to hold 35% of ENE's 85% indirect interest in SECLP.

Venezuelan capital markets laws may require a tender offer to be made prior to certain transfers of interest in Venezuelan companies. Vengas has consulted local counsel and does not believe any tender offer requirements will be triggered by the transfer to Prisma and related transfers.

(A) Industry Overview. LPG is the main source of heating and cooking fuel in Venezuela. Electric energy and natural gas are potential competitors, but electricity has been more expensive and the natural gas infrastructure is insufficiently developed. These alternatives therefore have not posed a competitive threat to LPG sales. The Venezuelan LPG market is divided into the regulated residential and unregulated commercial and industrial sectors. The LPG market is mature, and LPG consumption has generally correlated with population and economic growth in Venezuela. Vengas estimates that the LPG market had modest sales declines in 2001 and 2002, which are generally attributable to deteriorating economic and political conditions in Venezuela and PdVSA supply disruptions that began in December 2002 and continued through the first quarter of 2003, resulting from national strikes.

The LPG market in Venezuela has four primary sectors—supply, transport, filling, and distribution. The LPG supply chain begins at one of eight PdVSA-owned supply plants located throughout Venezuela. The LPG is transported from these facilities in specially designed heavy-duty vehicles to the filling plants, where it is stored and distributed to various LPG companies for distribution to end users. The filling plant sector stores LPG received from the PdVSA-owned supply plants and distributes the LPG to the distribution companies that operate in different localities or regions. At present, there are 29 companies, including Vengas, that operate the 74 filling plants throughout the country. The distribution sector transports LPG from the filling plants to the end user. There are 280 distribution companies. In 2002, Vengas believes that it distributed approximately 40% of all LPG in Venezuela and believes that Digas-Tropiven S.A., the second largest Venezuelan LPG distributor, distributed approximately 18% of the LPG sold in the country. Vengas and Digas-Tropiven S.A. are the only distributors that operate on a national basis. The remainder of the market is highly fragmented and commonly served by small to medium-sized family-owned businesses that limit distribution to a specific region or city.

(B) Property, Plant and Equipment. Vengas transports LPG from PdVSA's eight LPG processing and refinery plants located throughout Venezuela to Vengas's 25 filling plants using its fleet of 82 hauling trucks. Vengas owns its head offices in Guarenas and 24 out of its 25 filling plants. At the filling plants, Vengas fills its 3.5 million cylinders and its 52 bulk distribution trucks. Full cylinders are loaded onto Vengas's fleet of approximately 460 cylinder distribution trucks for delivery directly to customers, or for the smaller 10 kilogram cylinders, to a network of approximately 7,500 rack dealers. Vengas's bulk distribution trucks are used to transport LPG to fill bulk tanks installed at customer locations. In addition, Vengas owns approximately 9,600 storage tanks. Vengas leases 26 of its 38 branch offices and all of its sales offices.

Until March 2003, Vengas manufactured and repaired all of its cylinders at its cylinder factory. Vengas typically manufactured in excess of 200,000 new cylinders and repaired more than 300,000 cylinders per year. The factory was shut down, however, after Vengas determined that it would be more cost-effective, at least in the short term, to buy rather than manufacture cylinders and to outsource repairs of cylinders. As a result, Vengas is currently purchasing its cylinders and obtaining repair services from a third party that supplies the entire Venezuelan market. If the supplier does not deliver an adequate number or quality of cylinders, Vengas's operations could be adversely affected. Vengas is maintaining its cylinder factory and may reopen it if economic conditions or reliability concerns make it desirable to do so.

(C) Customers. Vengas's overall sales by volume declined by 2% in 2001 and by 5.8% in 2002, principally due to deteriorating economic and political conditions in Venezuela and PdVSA supply disruptions that began in December 2002 and continued through the first quarter of 2003. Refer to Section XIV.I.1.c., "Political Instability, Civil Unrest, and Regime Change" for further information on the risks related to political instability, civil unrest and regime change. Those events had a greater effect on commercial and industrial demand, which fell more than residential demand. Approximately 77% of Vengas's 2001 total sales and 80% of Vengas's 2002 total sales of LPG by volume were of Vengas brand LPG to residential customers at regulated rates. Approximately 13% of Vengas's 2001 total sales and 12% of Vengas's 2002 total sales of LPG by volume were of Vengas brand LPG to commercial and industrial bulk customers at non-regulated rates. The remaining 10% of Vengas's 2001 sales and 8% of Vengas's 2002 sales of LPG by volume were attributable to the sale and distribution of non-Vengas brand LPG.

(D) Supplier. Vengas purchases LPG on an as-needed basis from PdVSA at the tariff set by the Ministry of Energy and Mines. Vengas does not have any long-term LPG supply agreements with PdVSA. If PdVSA were to fail to supply LPG to Vengas, the only alternative would be to import LPG, which Vengas has never done and may be unable to do. Refer to Section XIV.I.2.c., "Concentration of Customers and Suppliers" for a discussion of the risks created by reliance on a limited number of suppliers.

Because of the importance of PdVSA to the total Venezuelan economy, and because it is state owned, it is highly impacted by political events. In December 2002, opponents of President Chávez organized a nationwide strike to call for an early referendum on the President's rule. The strikers nearly shut down the country's oil industry, drastically reducing the production of Venezuelan oil and its delivery to internal and external markets. Supply of LPG to Vengas was reduced to less than half. President Chávez declared the strikers' demands unconstitutional and enlisted the help of the military to maintain production. Since coming into office, President Chávez has severed or replaced approximately 17,000 employees, mostly management, of PdVSA's approximately 40,000 total employees. Refer to Section XIV.I.1.c., "Political Instability, Civil Unrest, and Regime Change" for a discussion of the risks presented by political instability, civil unrest, and regime change.

(E) Regulatory Environment. On October 1, 2000, the Ministry of Energy and Mines issued three permits to Vengas that authorize Vengas to transport and distribute LPG and manufacture, repair, and maintain LPG cylinders and tanks. These permits were granted with a term of 35 years, renewable for an additional 30 years, but may be revoked under certain extenuating circumstances, including upon the transfer of a permit without proper authorization from the Ministry of Energy and Mines or non-compliance with applicable provisions of law or the terms of the permit itself.

(F) Tariffs. The Ministry of Energy and Mines sets both the prices at which PdVSA sells LPG to distributors and the prices at which distributors sell LPG to residential consumers. Prices are not regulated for sales to the commercial and industrial sectors. The Venezuelan government heavily subsidizes the residential sector, often using PdVSA as a vehicle, because LPG represents a basic utility to a large percentage of the Venezuelan population. If this subsidy is discontinued, demand for LPG will likely decrease. The Ministry of Energy and Mines is required by regulation to set tariffs on a quarterly basis to achieve a target gross margin based on the operating costs of the "average" LPG distribution company. Despite this requirement, tariffs were increased by 16% in April 2002 for the first time in approximately 18 months. Effective December 1, 2002, tariffs at which Vengas sells LPG were increased by an additional 22%, and tariffs at which Vengas buys LPG from PdVSA were increased by 2%. Neither of the most recent increases, however, fully reflected accumulated inflation. Due to inflation, Vengas and the national LPG trade association are required frequently to petition the Ministry of Energy and Mines for tariff rate increases. At the same time, the Venezuelan government is under considerable political pressure from low-income constituents not to increase the price of any basic commodity, including LPG, and could likely continue to resist tariff increases. The Venezuelan government could potentially take other measures, such as establishing LPG cooperatives to compete with private LPG distributors or deregulating LPG tariffs. Because the regulatory mechanism has been inconsistently applied, Vengas is subject to price risk and no assurance can be given that the Ministry of Energy and Mines will provide for adequate margins. Refer to Sections XIV.I.1.a., "International Economic Slowdown" and XIV.I.1.b., "Regulatory Intervention and Political Pressure" for further information about the risks related to political and regulatory pressures on energy costs and tariffs.

(G) New Foreign Exchange Control Regime. In February 2003, the Venezuelan government announced the enactment of a foreign exchange control regime that restricts the convertibility and repatriation of foreign exchange and sets specified bolivar/dollar exchange rates. The specified exchange rates can be changed by the agency in charge of the regime and were changed in June 2003. All sales and purchases of foreign currency are required to be made through the Venezuelan central bank or a pre-approved commercial bank. In addition, private parties are required to sell any foreign currency they hold in certain cases. Vengas does not believe it fits into any of the categories that would require it to sell any foreign exchange it holds. While the framework of the new regime has been created, the government has not issued regulations required to implement the new laws. As a result, only a limited amount of currency has been exchanged under the new regime. If the specified exchange rate is further changed or if the exchange rate is allowed to float, Vengas may suffer exchange rate losses if it is unable to convert any excess bolivars it holds for some period and the bolivar devalues against the U.S. dollar during the period of inconvertibility. Vengas has not been approved to exchange currency under the new regime. In June 2003 it was required to use offshore dollar reserves to pay dividends. In August 2003, the Venezuelan government began offering dollar denominated sovereign debt that may be purchased with bolivars at the official exchange rate. Vengas purchased approximately 13 billion bolivars of Venezuelan debt and anticipates trading them in the secondary market at some point for dollars. This method of exchanging bolivars for U.S. dollars will cause Vengas to incur broker and related payments and also exposes Vengas to the additional risk that the value of the Venezuelan debt in the secondary market at the time of sale will be less than its purchase price. Refer to Sections XIV.I.1.c., "Political Instability, Civil Unrest, and Regime Change" for further information about the risks related to currency devaluations and exchange controls.

(H) Inflation and Devaluation Impacts on Venezuelan Tax Liability. Vengas's accounts are required to be adjusted for inflation under Venezuelan GAAP and Venezuelan tax laws. These adjustments and revaluations have a direct impact on the amount of Venezuelan income taxes paid. In general, the values of Vengas's non-monetary assets (*i.e.*, physical plant and equipment), liabilities, and equity accounts are adjusted on its balance sheet by the rate of inflation and the resulting increase or decrease is required to be reflected as income or loss, respectively, on Vengas's income statement. Both of these impacts can cause sizeable variations in the reported Venezuelan GAAP results on a year-to-year basis, the amount of Venezuelan taxes owed and dividends even while cash flow to the company remains stable.

(iv) Accroven, S.R.L. (Accroven). ENE owns an indirect 49.25% equity interest in Accroven, a Barbados company. Through its Venezuelan branch, Accroven owns and operates a fee-based NGL extraction, fractionation, storage, and refrigeration project. The other owners of Accroven are Williams International Venezuela Limited with a 49.25% interest and Tecnoconsult S.A. with a 1.5% interest.

The project commenced commercial operations in July 2001 and consists of facilities located in San Joaquin, Santa Barbara, and Jose, Venezuela. The San Joaquin and Santa Barbara facilities are NGL extraction plants with a combined total processing capacity of 800 MMcf/d (representing approximately 17% of Venezuela's total gas processing capacity). The Jose facilities consist of one NGL fractionation plant with a total processing capacity of 50 MBb1/d (representing approximately 18% of Venezuela's total NGL processing capacity), one propane compression refrigeration facility, two refrigerated storage tanks, and one pressurized storage sphere. The facilities are located on property owned by PdVSA Gas and leased to Accroven pursuant to servitude agreements that terminate in July 2021.

(A) Members' Agreement. Accroven is governed by a board of up to six managers. Each of Accroven's members is a party to a Members' Agreement under which EIV, an affiliate of ENE, and Williams International Venezuela Limited each appoints three managers.

The Members' Agreement contains preferential purchase rights, change-of-control provisions, and certain limitations on a member's transfer of its interest in Accroven. The Members' Agreement provides for dividend distributions on a quarterly basis or as frequently as possible (if less than quarterly) of all funds other than any legal solvency requirements, reserves required by Accroven's creditors, or reserves determined as reasonably necessary by its managers.

(B) Customer. Accroven's sole customer is PdVSA Gas, which purchases extraction and fractionation services and storage and refrigeration services from Accroven under two 20-year services agreements terminating in July 2021 and governed by Venezuelan law. PdVSA Gas's obligations under the services agreements are guaranteed by PdVSA. All hydrocarbons processed by Accroven pursuant to the services agreements are supplied by and belong exclusively to PdVSA Gas. Refer to Sections XIV.I.1.c., "Political Instability, Civil Unrest, and Regime Change" and XIV.I.2.c., "Concentration of Customers and Suppliers" for further information about the risks related to reliance on a limited number of customers.

The tariffs under the services agreements are primarily denominated and paid in U.S. dollars. They are intended to allow recovery of and to provide a return on Accroven's capital cost investment and to cover O&M expenses incurred. PdVSA Gas is obligated to make tariff payments under the services agreements as long as the relevant facilities are available unless there is a force majeure event. PdVSA Gas had been current in all payments under the services agreements until December 2002, when almost 17,000 of the 40,000 employees at PdVSA and PdVSA Gas were severed when they went on strike to protest policies of the Venezuelan government. On other occasions since the strike, PdVSA Gas has been delinquent in its payments for short periods of time because of administrative problems. Presently, PdVSA Gas is current in its payments. Refer to Section XIV.I.1.c., "Political Instability, Civil Unrest, and Regime Change" for further information.

Under the services agreements, PdVSA Gas is further obligated to supply fuel and other standard utilities, such as water and electricity, to Accroven. PdVSA Gas automatically deducts the charge for electricity from its monthly payments to Accroven. Since November 2001, Accroven has disputed the amount and method by which PdVSA Gas has calculated the electricity charge. Accroven is working to resolve this issue with PdVSA Gas. A failure to reach a resolution could have a material adverse effect on Accroven.

As required by the services agreements, ENE has posted bonds in favor of PdVSA in the aggregate amount of $32.5 million. Prisma may be required to replace these bonds, which may need to be cash collateralized.

The services agreements may be terminated due to an event of default or a force majeure event. Depending upon the cause of termination, PdVSA Gas may acquire the project facilities or all of the equity interest in Accroven or Accroven may decommission the facilities or sell them to PdVSA Gas. The amount that would be received in payment for any such sale would vary depending on the cause of termination.

(C) Associated Debt. The total cost of the project as of June 30, 2003 was $438.8 million and was financed by $200 million in loans from OPIC, which mature in May 2016, $132.3 million in loans from Eximbank, which mature in June 2013, and member equity contributions totaling $106.5 million. The OPIC facility is divided into two tranches and has been fully drawn. Tranche 1 was drawn for $90 million with a fixed interest rate of 6.60% and Tranche 2 was drawn for $110 million with a fixed interest rate of 6.99%. The OPIC spread for each tranche is 2%. This will increase to 2.5% for each tranche when the project reaches its completion date (as defined in the loan documents). As of June 30, 2003, approximately $175.3 million remained outstanding. Only $132.3 million of the $134,885,288 Eximbank facility was drawn. The Eximbank facility carries a fixed interest rate of 7.22%. As of June 30, 2003, approximately $119.1 million in principal was outstanding.

The OPIC and Eximbank credit facilities are secured by a lien, governed by New York law, on Accroven's contracts and accounts, a mortgage, governed by Venezuelan law, on the project facilities, and a pledge of the quotas in Accroven held by its members. The credit facilities impose a number of contractual restrictions, including, among others, restrictions on transfers of interest in Accroven and the payment of dividends.

ENE's bankruptcy and the failure by the ENE-affiliated contractors to achieve completion of the project under the loan documents led to defaults under the OPIC and Eximbank credit facilities. In June 2003, Accroven executed agreements with its lenders to obtain waivers of such defaults and to specify revised criteria that must be satisfied to achieve completion of the project (as defined in the loan documents), an event that must occur before dividends can be paid.

In February 2003, the Venezuelan government announced the enactment of a foreign exchange control regime that restricts the convertibility and repatriation of foreign exchange and sets specified bolivar/dollar exchange rates. Because Accroven is a Barbados company whose revenues are primarily in dollars paid to its accounts in New York, Accroven does not expect to be significantly affected by the new foreign exchange control regime.

(v) GasOriente Boliviano Ltda. (Cuiabá – GasBol). Refer to Section X.A.3.e(i), "Cuiabá Integrated Project" for further information.

(vi) GasOcidente do Mato Grasso Ltda. (Cuiabá – GasMat). Refer to Section X.A.3.e(i), "Cuiabá Integrated Project" for further information.

(vii) Transredes – Transporte de Hidrocarburos S.A. (TRSA) and the Bolivia-to-Brazil Pipeline (BBPL). TRSA provides domestic and export hydrocarbons transport and associated activities in Bolivia through its ownership and operation of approximately 1,800 miles of gas pipelines and approximately 1,700 miles of liquids (crude oil, LPG, NGLs, and diesel) pipelines. ENE owns an indirect 25% equity interest in TRSA through ownership of a 50% equity interest in TRH. TRSA owns 51% of GTB, which owns the Bolivian portion of the BBPL, and performs site operations and various other contracted services to GTB. TRSA owns 12% of TBG, which owns the Brazilian portion of the BBPL.

TRSA holds four 40-year concessions granted by the Bolivian government that permit TRSA to provide non-exclusive hydrocarbons transportation services for the domestic and export natural gas and liquids markets. TRSA has firm and interruptible transport contracts for service on each of the four concessions. The firm contracts all provide for ship-or-pay charges equal to approximately 97% of the total charge. The charges for the regulated interruptible tariff are the same as those for the firm tariff, but the interruptible tariff is paid on a usage basis.

TRH was created by ENE and Shell to acquire a 50% interest in TRSA in May 1997 in a closed-bid auction held by YPFB, the Bolivian state-owned oil and gas company. The winning bid, representing an investment commitment of $263.5 million, gave TRH a 50% ownership interest in TRSA, together with management control. Of the remaining 50% equity interest in TRSA, approximately 34% is held almost equally between two Bolivian pension funds, 9.66% is held by an affiliate of GECC, and the balance is held by other investors. TRH nominates four of TRSA's seven board seats. The Bolivian pension funds currently nominate three seats between them. TRSA is listed on the Bolivian Stock Exchange under the symbol TRD1U.

(A) Industry Overview. Much of Bolivia's major natural gas discoveries have come since 1998; however, only a small portion of these discoveries have been developed due to limited markets. Brazil is Bolivia's only current major export market, but even in Brazil export growth has slowed because of economic and other conditions in Brazil affecting the development and dispatch of thermoelectric power generation plants.

In the spring of 2003, a consortium led by Petrobras completed construction of Transierra, a natural gas pipeline that extends from the gas fields in southern Bolivia to Rio Grande. This line roughly parallels a pipeline owned by TRSA. At the present time the combination of the two pipelines provides the industry with a surplus of capacity. Petrobras has recently requested the Gas Supply Agreement between Petrobras and YPFB be renegotiated in an effort to reduce the price and the minimum take or pay quantities of gas Petrobras must purchase. If Petrobras is successful in reducing the quantities of gas it must purchase, there will be mid-term imbalance between the transportation capacity purchased by the producers and the amount of gas purchased under the Gas Supply Agreement. Although TRSA has firm, long-term contracts with its customers, the excess contracted capacity may result in efforts by some or all of the producers to reduce their capacity on either TRSA's pipelines or the Transierra pipeline. Other than the TRSA pipelines and the Transierra line, there are no other significant pipeline systems in Bolivia.

In connection with the Shell Settlement, affiliates of ENE and Shell entered into a Voting Agreement on September 26, 2003, to govern the ownership and control of TRH. Under the Shareholder Agreement the parties agree that all actions of TRH shall be made by mutual consent of such affiliates of ENE and Shell. Additionally, each shareholder is granted a right of first refusal to acquire the other shareholder's ownership interest in TRH if said party or its affiliate seeks to sell or otherwise transfer its interest in TRH to a third party. Each shareholder also has a right of first refusal to purchase the ownership interest held by the other shareholder if such shareholder or its affiliate experiences a change of control.

With respect to TRSA, in general, all decisions involving commitments in excess of $250,000 are reviewed by ENE and Shell and both parties must agree on the guidance that they will give the senior management team of TRSA with respect to feasibility and desirability of the recommendation. ENE has the contractual right to appoint the secretary of the board and the President of TRSA, and Shell has the right to appoint the chairman of the board and the Chief Financial Officer. Other officers are appointed as mutually agreed by ENE and Shell.

(B) Associated Debt. As part of the acquisition from YPFB of the 50% interest in TRSA, TRSA was required to assume outstanding indebtedness owed by YPFB. As of December 31, 2002, this debt totaled approximately $111.3 million in eight different tranches with varying payment schedules and maturities ranging from December 31, 2004 to June 30, 2032. In June and September 2001, TRSA issued bonds in an aggregate principal amount of $155 million. Twenty million dollars of the bonds mature on each of July 3, 2004, June 8, 2005, June 3, 2006, and May 29, 2007, and $75 million mature on August 6, 2009.

TRSA is seeking to obtain IDB/CAF financing in 2003. If obtained, this financing is intended to be used to fund capital expenditures. Two multilateral agencies recently agreed to participate in a $220 million facility with TRSA. TRSA expects to close this facility in the fourth quarter of 2003. TRSA's failure to obtain this financing could result in delays of planned capital expenditures or limit TRSA's ability to pay dividends for the foreseeable future.

(C) Customers. TRSA's gas pipeline network has a total capacity of approximately 690 MMcf/d. For 2003, TRSA has firm contracts totaling 639 MMcf/d. TRSA's transportation of liquids is largely associated with the production of natural gas and the customer base is very similar. The chart below lists TRSA's gas transportation customers and firm gas contract volumes from 2002 through 2007.

Firm Gas Contract Volumes as of July 2002

MMcm/d

(To obtain MMcf/d multiply figures below by 35.315)

	2002	2003	2004	2005	2006	2007
Gas Firm Contract by Customer						
Chaco	3.1	3.1	3.1	3.1	3.1	2.6
Andina Maxus	3.6	3.9	3.0	3.0	3.0	3.0
Pecom	1.0	1.1	1.1	1.2	1.2	1.2
BG	3.5	2.1	2.1	1.5	1.5	1.5
Vintage	0.6	0.8	0.4	0.0	0.0	0.0
TBS	1.1	1.1	1.1	1.1	1.1	1.1
Petrobras	3.0	6.0	6.0	6.0	6.0	6.0
Total Gas System	15.9	18.1	16.8	15.9	15.9	15.4

An important source of revenue for TRSA results from the obligation of Petrobras to pay TRSA surcharges mandated by the Bolivian government regulations for volumes contracted by Petrobras and transported through its Transierra pipeline. These revenues are projected by TRSA to be approximately $9.9 million in 2003, $15.5 million in 2004, and $20.6 million in each of the years 2005-2021. These revenues may not be realized if Petrobras refuses to pay the surcharge or may only be partly realized if Petrobras pays the surcharge on through-put volumes rather than volumes as contracted.

(D) Regulatory Environment. TRSA's gas and liquids transportation businesses are regulated public services in Bolivia and are governed by a number of laws, regulations, and administrative resolutions. Among these regulations are the 1996 Hydrocarbons Law No. 1689, Bolivia's Sector Regulation System Law No. 1600 and the Transportation Regulations for the Transportation of Hydrocarbons via Pipelines, Supreme Decree No. 26116. The administration of these laws and regulations is the responsibility of the Government and the Superintendent of Hydrocarbons of Bolivia's Sector Regulation System, who must approve the terms and conditions of any transportation agreements between TRSA and the producers/shippers.

Under the terms and conditions of the capitalization agreements under which TRSA obtained the pipeline system from YPFB, the Bolivian government required that the cost of transportation services during a four-year transition period from 1997 to 2001 be held at an artificially low level. The purpose of this subsidized, postage rate tariff (that is, a tariff independent of the distance the product is transported) was to encourage gas exploration and production and to allow participants in the energy markets in Bolivia to gradually make adjustments in anticipation of an economically based tariff.

TRSA was permitted to recognize as an asset, earning interest at 7% per annum in a "deferred account" an amount of deferred revenues resulting from the difference between the four-year transition period tariffs and the return permitted under the Transportation Regulations. The transition period ended May 16, 2001, and thereafter TRSA was allowed to capitalize the accumulated balance in the deferred account as a normal return-generating asset, and annually expense as amortization a portion of that amount through the post-transition period tariffs. As of December 31, 2002, the deferred account balance was $141.9 million. The deferred account surcharge is applied to all volumes, export and domestic, including volumes shipped by third parties.

TRSA receives domestic surcharges on all export shipments of gas transported in Bolivia regardless of whether the gas is transported on TRSA's system or by third parties. A new regulation would be required to extend the domestic surcharge beyond the date in 2006 when it is scheduled to expire. Failure to extend the subsidy would adversely affect TRSA's revenues by approximately $16 million per year and would impact the ability of TRSA to pay expected dividends.

(E) Tariffs. The 1996 Hydrocarbons Law requires that all tariffs provide the lowest transportation cost to the shippers while providing the transporter with a reasonable rate of return on equity. The price of transportation services in Bolivia for each of the four concessions is calculated using a "cash flow" methodology. Rate cases occur every four years under Bolivian law, and the next rate case filing for TRSA will be in May 2005. Agreement on a tariff requires agreement on anticipated future returns. Under this structure, TRSA recovers its capital expenditures, its cost of capital, the amortization of the deferred account, operating costs and a reasonable rate of return (currently targeted at 12.5%) plus inflation (U.S.) on equity, which totals approximately 14.9% currently. The regulations, however, provide for a deemed 60/40 debt-to-equity structure for the purposes of calculating the return on equity. TRSA's debt-to-equity as of year end 2002 is approximately 42/58.

The 1996 Hydrocarbons Law and related Supreme Decree No. 26116 also provide for a re-adjustment to the tariffs if (i) at any time actual volumes are 8% lower or higher (cumulatively) than projected rate case volumes; (ii) there is any change in tax legislation or (iii) there is a significant change, in either direction, in the investment made by TRSA. Refer to Section XIV.I.1.b., "Regulatory Intervention and Political Pressure" for further information about the risks related to tariff-setting.

(F) Environmental Matters. TRSA signed an agreement with the government to reach compliance with Bolivian government environmental manifestos by May 2004. TRSA agreed to meet 189 specific environmental requirements and as of June 2003 TRSA had completed 159. Twenty of the outstanding requirements arose before the pipeline assets were transferred to TRSA and are subject to a specific agreement with the government signed on July 10, 2001.

TRSA prepares an environmental impact assessment study and submits it for approval from the government, which is required for any new infrastructure project, including expansions. TRSA has completed and has received environmental licenses for 27 projects since 1997.

The hydrocarbon transport industry has inherent risks of leaks and spills. In January 2000 a TRSA pipeline suffered a major oil spill that resulted in approximately $50 million of clean-up and remediation costs to TRSA. TRSA has filed claims with its insurers to recover its losses from the oil spill.

(G) Gas Transboliviano S.A. (GTB). GTB owns and operates the approximately 350-mile Bolivian portion of the BBPL, which is a regulated pipeline that transports natural gas from Rio Grande, Bolivia, to Mutun, Bolivia, at the Brazilian border, where it interconnects to TBG, the Brazilian portion of the BBPL. GTB relies on a single customer, YPFB, as the source of nearly all of its revenues under its current long-term contracts for firm capacity and gas transportation services. The YPFB contracts account for 1.062 bcf/d of the approximately 1.1 bcf/d of capacity currently available on the GTB pipeline. Refer to Section XIV.I.2.c., "Concentration of Customers and Suppliers" for further information. All tariff charges associated with the gas shipped by GTB under its transportation agreements with YPFB are paid for directly by Petrobras, the Brazilian state-owned oil and gas company, under direct payment agreements with GTB. GTB's contracts with Petrobras and YPFB are "ship-or-pay" contracts that require Petrobras to pay substantially all of the amounts due under the contracts as capacity payments regardless of whether YPFB actually ships gas through the pipeline. Petrobras and YPFB have preferred treatment on the GTB pipeline relative to other shippers. GTB's pipeline presently is flowing at approximately 50% of capacity.

Excluding its 12.75% indirect interest owned through TRSA, ENE owns a 17% equity interest in GTB. TRSA owns 51% of GTB's equity and provides operation, maintenance, and administrative services to GTB under a 20-year agreement. Of the remaining equity, an affiliate of Shell owns a 17% interest, an affiliate of Petrobras owns an 11% interest, an affiliate of British Gas owns a 2% interest, and an affiliate of El Paso owns a 2% interest. GTB is managed by a board of directors consisting of five members, comprised of two TRSA nominees, one ENE nominee, one Shell nominee, and one director nominated by majority vote of Petrobras and the other shareholders. Certain major decisions, including the incurrence of debt in excess of $10 million, changes to the dividend or tax policy, and amendments to the bylaws, require the approval of shareholders holding 86% of the shares of GTB, thus giving Petrobras and the other shareholders voting together a veto over such decisions.

In connection with the Shell Settlement, certain affiliates of ENE and Shell entered into a Pipeline Voting Agreement to address ENE's and Shell's respective ownership interests in GTB. The parties agreed to vote their respective equity interests in GTB such that no approval relating to any of the following matters would be given by either party unless both parties agreed on: (i) certain expenditures in excess of $250,000, (ii) transfers of all or a substantial part of GTB's assets, (iii) any amendment to GTB's organizational documents, (iv) any decision to incur indebtedness in excess of $250,000 in the aggregate, (v) any appointment, removal, elimination, creation or modification of all senior manager's positions, (vi) any decision appointing or removing GTB's auditors, and (vii) any other material transaction relating to GTB. Refer to Section X.A.3.e(i), "Cuiabá Integrated Project" for further information about the Shell Settlement.

As of June 30, 2003, GTB's pipeline and compression facilities cost approximately $600 million to construct. GTB financed this construction with funds from Petrobras, GTB's shareholders, third parties, and cash from operations. Petrobras provided the majority of the funds used to construct the GTB pipeline system by making advances in exchange for the reservation of firm capacity in the pipeline and has a lien on certain GTB pipeline assets as security for the advances. As of June 30, 2003, GTB's total outstanding indebtedness was approximately $557 million. Historically, GTB has not paid dividends to its shareholders. Any future dividends are subject to restrictive covenants in GTB's mezzanine financing; in addition, dividends cannot be paid until outstanding development cost advances of approximately $22 million, which includes accrued interest as of June 30, 2003, have been repaid to GTB's shareholders.

Petrobras has claims of approximately $17.7 million against GTB relating to alleged shortfalls in gas tendered by GTB, non-compliance with provisions in the gas transportation agreements and related matters. These claims are the subject of ongoing negotiation between GTB and Petrobras and as of June 30, 2003, GTB had reserved $5.8 million for these claims.

GTB and Petrobras entered into an agreement in September 2001 under which Petrobras agreed to repay GTB for costs incurred by GTB for installing 35,000 hp of additional compression on the GTB pipeline. As of June 30, 2003, approximately $33.7 million was payable to GTB under that agreement, which is scheduled to be repaid monthly with interest over a period of 10 years. In addition, as of June 2006, another approximately $15.7 million is anticipated to become due and payable to GTB under that agreement, which would be repaid monthly by Petrobras to GTB with interest over a period of 10 years.

(H) Transportadora Brasileira Gasoduto Bolivia-Brasil S.A. (TBG). TBG owns and operates the approximately 1,600-mile Brazilian portion of the BBPL, which is a regulated pipeline that transports natural gas from an interconnection with the GTB pipeline at the Bolivian border to southeastern Brazil. As of the first quarter of 2003, Petrobras accounted for over 98% of TBG's volume and British Gas accounted for the remaining 2% of TBG's volume. TBG's contracts with Petrobras are U.S. dollar based "ship-or-pay" contracts that require Petrobras to pay substantially all of the amounts due under the contracts as capacity payments regardless of whether Petrobras actually ships any amounts of gas through TBG's pipeline. Because TBG's contracts are denominated in U.S. dollars but payable in Brazilian reais, significant devaluation of the Brazilian real against the U.S. dollar in 1999 and 2002 has made it more expensive for Petrobras to use TBG's transportation capacity.

Excluding its indirect 3% interest owned through TRSA, ENE owns a 4% equity interest in TBG. Petrobras indirectly owns 51% of TBG's equity and the balance of the equity is held by affiliates of TRSA (12%) and Shell (4%) and by a joint venture between TotalFina, British Gas, and El Paso (29%). Petrobras's position as both the controlling shareholder and the most significant customer of TBG creates an inherent conflict that may disadvantage TBG and its other shareholders. Petrobras and the joint venture owned by TotalFina, British Gas, and El Paso have the ability to direct the management of TBG, to control the election of a majority of its directors, and to determine the outcome of any matter put to a vote of TBG shareholders that does not require supermajority approval. TBG is managed by a board of directors consisting of six members, five of whom are to be nominated by a majority vote of such parties, and the remaining director is to be nominated by a majority vote of ENE, Shell, and TRSA. In connection with the Shell Settlement, certain affiliates of Shell and ENE entered into a Pipeline Voting Agreement to address ENE's and Shell's respective ownership interests in TBG. The parties agreed to vote their respective equity interests in TBG such that no approval relating to any of the following matters would be given by either party unless both parties agreed on: (i) certain expenditures in excess of $250,000, (ii) transfers of all or a substantial part of TBG's assets, (iii) any amendment to TBG's organizational documents, (iv) any decision to incur indebtedness in excess of $250,000 in the aggregate, (v) any appointment, removal, elimination, creation or modification of all senior management positions, (vi) any decision appointing or removing TBG's auditors, and (vii) any other material transaction relating to TBG. Refer to Section X.A.3.e(i)., "Cuiabá Integrated Project" for further information about the Shell Settlement.

Pursuant to a shareholders' agreement, each shareholder has a right of first refusal if any shareholder decides to sell some or all of its TBG shares to a third party.

(viii) Centragas – Transportadora de Gas de la Region Central de Enron Development & Cia., S.C.A. (Centragas). ENE, together with Ponderosa, indirectly owns a 50% equity interest in Centragas. Tomen Corporation and Promigas each owns a 25%

equity interest in Centragas. EDC, an affiliate of ENE, is the general partner of Centragas. Centragas owns and operates the 359-mile Ballena – Barrancabermeja natural gas pipeline in Colombia pursuant to a Transportation Services Contract that expires in February 2011. Centragas originally entered into the Transportation Services Contract with Ecopetrol, the state-owned oil company of Colombia. In 1998, Ecopetrol assigned the contract to Ecogas, a state-owned gas transportation company, but Ecopetrol has not been released by Centragas from its obligations under the contract. Under the Transportation Services Contract, Centragas transports gas exclusively for Ecogas. Centragas does not sell or market natural gas, and tariffs under the Transportation Services Contract are not subject to governmental regulations relating to the transportation of natural gas. Upon the expiration of the Transportation Services Contract in February 2011, Ecogas will have the option to purchase the pipeline from Centragas for approximately $2.2 million. The pipeline is operated by Promigas, and EIDS, an affiliate of ENE, has a Technical Services Agreement with Centragas that matches the term of the Transportation Services Contract.

The project was financed by a private placement of $172 million of 10.65% Senior Secured Notes Due 2010 issued by Centragas pursuant to an indenture and equity contributions by ENE affiliate partners of $45 million. Following a June 1, 2003 payment, the outstanding principal balance on the notes was $97,662,438. The notes are secured by the pipeline and substantially all of Centragas's other assets.

The indenture permits Centragas to make loans to its partners and their affiliates under certain conditions. Such loans have been made to affiliates of ENE (of which $39,904,010 remained outstanding as of June 30, 2003). Through an escrow arrangement, these loans are repaid from the proceeds of dividends payable to the ENE affiliate partners. As a result, the ENE affiliate partners will not be able to receive any cash dividends, to the extent declared and paid, until the outstanding loans to ENE affiliates are repaid in full, which is not expected to occur until 2012 when the project is scheduled to be liquidated. Until Prisma is able to meet the requirements to obtain additional partner loans from Centragas, the only source of cash to Prisma from the project prior to liquidation will be the fees under the Technical Services Agreement.

d. Power Distribution

(i) Elektro Eletricidade e Servicos S.A. (Elektro). Elektro is a Brazilian LDC operating in the states of São Paulo and Mato Grosso do Sul, Brazil. Elektro's concession area covers 223 municipalities in the state of São Paulo, and 5 municipalities in the state of Mato Grosso do Sul, encompassing approximately 56,000 miles of distribution lines. As of June 30, 2003, Elektro had approximately 2,200 employees.

Pursuant to a national power sector privatization program, Elektro was created by a spin-off of the Companhia Energética de São Paulo power distribution division in January 1998. Companhia Energética de São Paulo was previously a state-owned integrated energy company providing power generation, transmission, and distribution in São Paulo. In a series of transactions in 1998 and 1999, ENE and its affiliates acquired a 99.62% economic interest and a 99.96% voting interest in Elektro. Three Brazilian limited liability companies, EPC Ltda., EIE, and ETB, which are indirectly controlled by ENE and its affiliates, including Whitewing LP, hold 99.62% of Elektro's capital stock. There is no shareholders' agreement among these parties. The remaining 0.38% of the capital stock is publicly held.

It is anticipated that Elektro will continue its primary strategy of cost leadership and the strengthening of its brand with a focus on customer service and high standards in power dependability and quality. Furthermore, Elektro's management team has taken a leadership role in industry discussions with governmental authorities regarding the development of the Brazilian energy regulatory framework.

(A) Industry Overview. Despite the economic difficulties facing the country since the early 1980s, according to the Brazilian Ministry of Mines and Energy, overall electricity consumption in Brazil grew from 151 TWh in 1985 to 226 TWh in 1994, equivalent to a 4.6% CAGR. In the period following the real stabilization plan (1994 - 2000), electric consumption grew at a 5.3% CAGR, reaching 307 TWh in 2000. During this period, the fastest growing market segments in Brazil were the residential segment with a CAGR of 6.9% and the commercial segment with a CAGR of 8.7% according to the Ministry of Mines and Energy.

Privatization efforts in the Brazilian power industry began in the distribution sector. Currently, approximately 75% of the total energy market and approximately two-thirds of the 70 distribution companies in Brazil are owned by private investors. Privatization auctions occurred between 1995 and 2000, and a total of approximately $27 billion was invested in the distribution sector by major players including ENE and AES; EDP – Electricidade de Portugal, Endesa, and Iberdrola (Spain); EDF – Electricité de France; and VBC (Brazil).

Hydroelectric power constitutes approximately 90% of Brazil's total installed capacity. Abnormally low rainfall, lack of investments in generation facilities, and depletion of water reserves led the Brazilian government to impose a severe energy rationing program from June 2001 through February 2002. Brazil's electricity consumption was reduced by 16.5% during this period. This shortage in supply led to increased efforts to develop thermal energy plants, although such development slowed in 2003 as hydroelectric resources returned to more normal levels. Even after the removal of rationing restrictions, consumption, according to the Ministry of Mines and Energy, grew only 2.5% in 2002 compared to an average of 5.3% over the prior six years. According to the Ministry of Mines and Energy, the growth in electric consumption in Brazil over the next five years is expected to be approximately 6% per year and in the southeastern region 5.6% per year.

Since 2001 several LDCs have faced severe losses and deteriorating financial conditions as a result of the rationing impacts, reduced electrical consumption, delay of uncontrollable costs tariff pass-through, and foreign exchange devaluation impacts related to U.S. dollar denominated debt. The Brazilian government's electricity rationing program implemented from June 2001 to February 2002 negatively impacted Elektro's revenues by R$219.2 million ($92.7 million). Furthermore, the delay of the pass-through of 2001 uncontrollable costs to Elektro tariffs caused Elektro additional losses of R$58.9 million ($24.8 million). Another prolonged electrical energy crisis could trigger another federal rationing plan, have adverse effects on the Brazilian economy, and lead to a downturn in the level of economic activity, all of which could adversely affect Elektro's operating results and financial condition.

(B) Concession Agreement. Elektro holds a 30-year renewable Concession Agreement, the first term of which expires in 2028, which provides exclusive distribution rights within the concession area. Elektro may seek an extension of the Concession Agreement for an equal term of 30 years by submitting a written request accompanied by proof of compliance with various fiscal and social obligations required by law. Extension of the Concession Agreement by ANEEL is discretionary and based on technical reports by the agency regarding the dependability and quality of service rendered by Elektro in the primary term of the concession. Elektro's Concession Agreement and federal law allow for termination of the concession in the following situations: (i) expiration of the contractual term; (ii) expropriation for the public good (which requires payment to Elektro by the Brazilian federal government); (iii) forfeiture (by failure of concessionaire to honor concession obligations); (iv) rescission by concessionaire (in event that the federal government does not honor its obligations); (v) annulment arising from irregularity associated with granting of the concession; and (vi) bankruptcy or dissolution of Elektro. The federal government also has the authority to intervene in the administration of the concession if Elektro fails to comply with its obligations under the concession.

As part of the approval by ANEEL of a restructuring in December 1998 of ENE's interests in Elektro through a reverse merger transaction, the Concession Agreement was amended pursuant to the First Amendment to the Concession Agreement to include an annual capitalization test to measure the impact of the merger on Elektro. The financial impact of the merger is computed based on the inflows (tax and dividend savings) and outflows (interest and principal paid) generated by the merger. If the net result is positive, the balance is carried forward to the next year. If it is negative, Elektro's controlling shareholder EPC Ltda. has to recapitalize Elektro in an amount equivalent to the negative balance computed. As of June 30, 2003, $314 million of Elektro's intercompany debt due in December 2008 has to be considered in the financial flow computation of the capitalization test as interest and principal are paid. Depending on the results of the annual capitalization test, Elektro may have an impaired ability to pay interest and principal on its inter-company loans.

(C) Share Redemption Transaction. On January 3, 2001, Elektro's shareholders approved a share redemption transaction pursuant to which the shareholders would receive payments of R$676 million in quarterly installments from 2001 to 2005. As of June 30, 2003, payments to shareholders totaled $72.1 million (R$158.2 million) with an outstanding balance of $146.9 million (R$518.8 million). ANEEL notified Elektro on February 3, 2003 that the share redemption transaction should have been pre-approved by the agency and ruled that (1) the transaction should be reversed and (2) the shareholders should reimburse Elektro for the $72 million already received. On February 18, 2003, Elektro filed an appeal, which is still pending. If Elektro's majority shareholders are ultimately required to reimburse Elektro, they would have to seek the necessary funding from Prisma or otherwise adequately recapitalize Elektro.

On March 14, 2003, Elektro submitted a proposal to ANEEL to amend the original share redemption transaction to (1) maintain the original payment schedule (R$1.2 million outstanding) to the minority shareholders; (2) to include the past and future payments to controlling shareholders of $218 million (R$673.7 million) in the capitalization test computation set forth in the First Amendment to the Concession Agreement; and (3) to limit the future payments to the controlling shareholders by the positive balance of the capitalization test financial flow. If ANEEL accepts Elektro's proposal, Elektro currently believes that its financial flow balance would be enough to offset the reimbursement of the payments already made to the controlling shareholders through September 2001. Elektro's estimates indicate that if ANEEL accepts the proposal the remaining payments to the controlling shareholders would occur from 2005 through 2012. As of June 30, 2003, ANEEL has neither responded to Elektro's proposal, nor confirmed its request to reverse the transaction.

In addition, on March 14, 2003, the Comissão de Valores Mobiliários, the Brazilian securities commission, sent a notification to Elektro, challenging the legal grounds for the share redemption transaction. Elektro filed a response to the commission on March 27, 2003. In July 2003, Elektro was informed by its external counsel that the commission has initiated an administrative appeal process. Subsequently Elektro sent a letter to Comissão de Valores Mobiliários attaching its appeal previously filed with ANEEL on February 18, 2003. As of August 5, 2003, Elektro has not received any reply from the commission.

(D) Regulatory Environment. The Brazilian electricity sector is subject to regulation by ANEEL. ANEEL is an independent agency funded through contributions in the tariffs with its board of directors selected by the Brazilian President and approved by the Senate.

As a Brazilian publicly-held company with stock registered on the São Paulo Stock Exchange, Elektro also has to comply with disclosure requirements of the Comissão de Valores Mobiliários, including filing quarterly and annual financial statements and forms describing the company's corporate governance.

In December 2001, Brazilian governmental authorities and the LDCs agreed to an extraordinary tariff increase of approximately 5% to recover the rationing impacts on revenues and the delay of the pass-through of 2001 uncontrollable costs (Parcel A) to tariffs. To provide near-term relief, it was agreed that Brazilian National Bank for Economic and Social Development would finance 90% of such losses.

ANEEL adopted resolutions in November 2000 providing that the LDCs are responsible for expanding and improving the transmission grid of Companhia de Transmissão de Energia Elétrica Paulista S.A., the state-owned transmission company of São Paulo. Controversies have arisen as to whether the LDCs should pay connection charges to fund the transmission company, which would be passed through to tariffs, or invest directly in the transmission grid with their own resources. If Elektro is required to invest directly, such investment may exceed $50 million from 2003 to 2007 and reimbursement of such amount is contingent on the investment being deemed a reimbursable expense in Elektro's next annual tariff review and subsequent tariff adjustments.

(E) New Power Sector Model. On July 25, 2003, the Conselho Nacional de Política Energética – CNPE (Energy Policy National Council) announced proposed guidelines for the reform of the Brazilian power sector model. Members of the energy sector now have the opportunity to review and provide comments to the proposed guidelines. The main principles contained in the draft guidelines are that there must be: (i) a public service oriented electrical energy sector, (ii) government planning of generation and transmission expansion, and (iii) 100% contract commitments for all LDC power requirements with CNPE oversight. Additionally, the guidelines provide that there will be two markets for contracting power. The first market will be a regulated tariff pool for LDCs, generation public utilities, and the independent power generators if they elect to participate. The second market will include free customers and independent power generators with freely negotiated prices. Under the draft guidelines, each consumer with demands higher than 3MW will have to notify its LDC at least 5 years in advance to be allowed to purchase power from third parties. The government intends to start implementation of these guidelines in January 2004. This new arrangement is still subject to further discussions, changes in the existing regulatory and legal framework and congressional approval.

(F) Tariffs. Tariffs for distribution companies are periodically reset and reviewed by ANEEL. Elektro's tariffs were reset in August 2003, the fifth anniversary of the Concession Agreement, and will be reset every four years thereafter. ANEEL's proposed tariff review methodology includes in the rate base all of Elektro's assets at market replacement cost and adopts a model distribution company as the benchmark for operational costs. Members of the industry are still discussing with ANEEL the model company concept and its adverse effects on operational cost, labor relations, and financial obligations. Any asset base evaluations (provided by ANEEL-certified consultants) used in the tariff review methodology are subject to subsequent ANEEL audit and revision. If the outcome of the tariff review is not favorable, Elektro might need to restructure terms of its intercompany loans by (i) rescheduling maturity dates of interest and principal, (ii) reducing the coupon rate, or (iii) converting debt into equity.

Under Elektro's Concession Agreement, tariffs are adjusted on August 27 of each year based on Elektro's unit cost per kWh at the time of the last adjustment based on actual increases in Elektro's non-controllable costs per unit and for inflation commensurate with its controllable costs per unit since that time. Effective with the next adjustment, an "X" factor will reduce the inflation adjustment every year between reset dates to share efficiency and productivity gains with customers. Such non-controllable costs are monitored throughout the year through a tracking account and include, among others, power purchase costs (with foreign exchange adjustments in respect of the Itaipu contract discussed below), RGR (a reserve fund created by the Brazilian government to compensate companies for certain assets if the concession has been revoked), CCC (a fuel cost surcharge levied on all consumers), and certain sales taxes. In August 2002, Elektro received a tariff increase of 14.21%, which was consistent with Elektro's expectations and with increases received by other LDCs in the sector. In addition to these specific adjustments, Elektro's tariffs may be reviewed at any time to restore the "financial and economic equilibrium" of the Concession Agreement. Refer to Section XIV.I.1.b., "Regulatory Intervention and Political Pressure" for further information about the risks of regulatory intervention.

(G) 2003 Tariff Review. On August 27, 2003, ANEEL released Elektro's tariff increase of 27.93%, of which 20.25% became immediately effective. The remaining portion will be added to the controllable costs in the three subsequent annual tariff adjustments starting in 2004. The preliminary "X" factor is 2.38%. The methodology for determining the final "X" factor is not yet available. It will be annually adjusted based on LDC performance as determined through a customer survey. ANEEL has indicated that the annual adjustment also may capture productivity gains caused by market growth.

(H) Market. The majority of Elektro's regulated customer base is comprised of commercial and small and mid-sized industrial customers and higher-margin residential customers. Based on 2002 revenues, Elektro's regulated customers were 36% industrial, 35% residential, 14% commercial, 10% public/government, and 5% rural. Over the past seven years Elektro has experienced a 4.4% average annual growth rate in its customer base. Additionally, energy consumption in Elektro's concession area grew between 2.7% and 7.5% in each of the past seven years with the exception of 2001 when the energy rationing program was in place. The rationing program from June 2001 to February 2002 reduced energy consumption by 20.8% in the Elektro concession area compared to the June 2000 to February 2001 period. Elektro's operating results fluctuate based on the overall level of economic activity in Brazil and the disposable income level of consumers. Elektro has electricity sales contracts with each of its large customers with terms ranging from two to five years.

Customers in Elektro's service territory with demand higher than 3 MW have the option, after the expiration of their current contracts, to buy power from other LDCs, directly from a generator, or from an energy marketing company. The distribution service and the connection to the LDC system will continue to be contracted with the LDC, which would charge a regulated distribution tariff. However, there can be no assurance that ANEEL will set this tariff at a level that is satisfactory to Elektro. To mitigate the risk of Elektro's customers choosing to purchase power from other suppliers, Elektro's shareholders have established a marketing company that can enter into pure commodity contracts with these customers. There can be no assurances that the marketing company will be successful in capturing all profitable commodity customers that elect to unbundle their energy purchases, and Elektro's operating results may be negatively impacted accordingly. The loss of these customers may reduce Elektro's ability to recover the rationing revenue losses and uncontrollable costs within the 59-month maximum recovery period imposed by ANEEL for the 5% extraordinary tariff increase because this customer group pays an unbundled distribution tariff which does not include the extraordinary tariff increase. Elektro projections indicate that while the rationing revenue losses could be recovered within the 59 month recovery period, the uncontrollable costs may not be fully recovered within this period. Based upon a legal opinion provided by outside counsel, Elektro believes that the recovery period for the uncontrollable costs can be extended beyond the ANEEL-imposed 59 month recovery period. This issue is under discussion between the Brazilian LDC association, ABRADEE, and ANEEL.

(I) Brazilian Wholesale Market. The Brazilian Wholesale Market, which represented approximately 5% of Elektro's revenues during 2001 and 2002, is responsible for settling the contractual differences in the Brazilian power market. Due to the lack of clear regulations and a series of injunctions filed by several market agents, no payments were made from September 2000 to December 2002. Fifty percent of the outstanding receivables were due to be paid in January 2003, with the expectation of receiving $19.4 million (R$68.6 million). Due to late and partial payments, Elektro collected payments in January, February, and March totaling $17.1 million (R$61.0 million). Payment of an additional $1.4 million (R$5.0 million) has been blocked by an injunction. After the conclusion of an independent federal audit of the accounting, calculation process and amounts involved, settlement of the remaining 50% of receivables occurred in July 2003. Elektro effectively collected $13.6 million (R$40.4 million) in July and $7.4 million (R$21.9 million) has been blocked by injunctions. As a result, the total past due outstanding balance to Elektro is $2.4 million (R$7.0 million).

(J) Power Supply. Currently, almost 100% of Elektro's energy requirements are supplied by long-term contracts. Twenty-one percent is purchased from the large Itaipu hydroelectric generation facility, and most of the remainder is purchased under contracts with affiliates of each of Companhia Energética de São Paulo (CESP), Duke, and AES. Under these contracts, Elektro was required to buy a take-or-pay volume of approximately 80% of forecasted demand in 2002. The take-or-pay volume declines 25% per year beginning in January 2003 and the contracts terminate at the end of 2005. These contracts are currently priced at $16/MWh (R$56/MWh) on average. Prices are denominated in local currency and adjusted annually by inflation.

Itaipu's tariff is priced on demand, indexed to the U.S. dollar, and tied to the capital and operating costs of Itaipu. After prolonged negotiations with ANEEL, the foreign exchange risk inherent in this contract is now mitigated because the power purchase costs paid to Itaipu are passed through to the customers through a tracking account mechanism. Although the tracking mechanism mitigates foreign exchange risk of the dollar denominated contract, it does not provide full risk coverage, as the tracking account is computed on a monthly basis, but is only applied once a year in the yearly tariff adjustment. Therefore, a significant devaluation of the real might increase working capital requirements between two consecutive annual tariff adjustments dates. Refer to Section XIV.I.1.d., "Devaluations of Foreign Currencies" for further information about the risks of currency devaluations. In 2002 Elektro contracted 434 MW of capacity with Itaipu at a rate of $20.1988/kW-month. For 2003 the rate is $17.55/kW-month, equivalent to $30/MWh (R$106/MWh). On April 4, 2003, a new regulation (Portaria Interministerial 116) postponed pass-through of the tracking account values related to the 2002-2003 period until the 2004 tariff adjustment. A loan from the Brazilian National Bank for Economic and Social Development to advance such amounts to the LDCs has been established by means of Presidential Provisional Measure No. 127, effective August 4, 2003. Such measure has been approved by the Brazilian congress and should be made into law by the end of 2003. Elektro should receive from BNDES R$91.4 million (US$31 million), which is the balance as of August 27, 2003, that has been approved by ANEEL. The disbursements are expected to occur as follows: (i) 50% in November 2003; (ii) 30% in February 2004; and (iii) 20% in May 2004.

Since January 2003 LDCs have been required to contract at least 95% of their power needs through long-term contracts (more than 6 months) and buy their power needs through ANEEL-regulated auctions. A decree issued on July 8, 2003, allowed LDCs to amend their contracts with public service generators, until December 31, 2004, to purchase additional power limited to the original contracted volumes at the current prevailing prices. Elektro's current estimates indicate that Elektro is fully contracted for 2003. For 2004, Elektro covered its needs through an amendment of the CESP contract (295 MW), which was approved by ANEEL, and as of June 30, 2003 estimated that it will need to enter into contracts through auctions to buy 800 MW for 2005. Although Elektro will seek to obtain full pass-through to tariffs of the energy costs purchased at auctions, ANEEL may not include the auction contracts in the tracking account mechanism, which would not allow Elektro to recover eventual intra-year cost increases originated by such contracts and would negatively affect its operating results.

(K) Dividends Policy. Elektro's Bylaws provide for yearly payment of a minimum dividend equal to 25% of its net profit, which is the minimum annual dividend a corporation is obligated to pay under the Brazilian corporate law. The last year for which Elektro had a net profit under Brazilian GAAP and was able to pay dividends was 1998.

(L) Debt Overview. Elektro's consolidated indebtedness as of June 30, 2003 totaled $843 million, of which 59% was composed of U.S.-dollar-denominated intercompany obligations. Seventy-four percent of Elektro's third-party debt is U.S.-dollar-denominated and must be repaid from 2007 through 2012. Elektro expects its subsidiary Terraco Investment Ltd. to extend the maturity of its $179 million non-interest bearing loan payable to EDF that currently matures in 2004. As the bulk of Elektro's foreign exchange exposure is not hedged and Elektro's revenues are real-based, devaluation of the real and continued currency volatility would negatively impact Elektro's future earnings and cash flow, and could also hurt its ability to meet foreign currency interest and principal debt obligations.

The following table shows consolidated debt as of June 30, 2003 for Elektro, Terraco Investment Ltd., EPC Ltda., EIE, and ETB.

US GAAP ELEKTRO CONSOLIDATED DEBT STRUCTURE

As of June 30, 2003 (principal plus accrued interest to date)					$ Million – Fx Rate @ 2.8720		
	Maturity	Interest Rate	Principal	Interest Payment	Short Term	Long Term	Total
Third Party Debt							
Debt in R$							
BNDES Capex	Jun 2003 to Nov 2006	TJLP+3.2% ~ 3.85%	Monthly	Monthly (1)	5.6	14.5	20.1
Eletrobrás Financing	Mar 2007 to Oct 2007	RGR+5%	Monthly	Monthly	0.3	2.1	2.4
Debenture	May 2005	IGPDI+11.4%	Bullet	Annually	0.1	6.6	6.7
BNDES Rationing/ Parcel A Financing	Jan 2007	SELIC+1.0%	Monthly	Monthly	14.2	44.6	58.8
Shares Redemption (minority shareholders)	June 2005	-	Quarterly	None	0.2	0.2	0.4
Debt in $							
ETB / BCI (2)	Dec 2012	4.15%	Semi-annual (3)	Semi-annual	12.9	244.8	257.7
Sub-total					33.3	312.8	346.1
Intercompany Debt							
Debt in US$							
EBPH-IV	Dec 2008	15%	Bullet	Quarterly	-	314.1	314.1
EDF	Dec 2004	0%	Quarterly	None	27.5	151.6	179.1

US GAAP ELEKTRO CONSOLIDATED DEBT STRUCTURE							
As of June 30, 2003 (principal plus accrued interest to date)					$ Million – Fx Rate @ 2.8720		
	Maturity	Interest Rate	Principal	Interest Payment	Short Term	Long Term	Total
Other	-	-	-	-	-	3.3	3.3
Sub-total					27.5	469.0	496.5
Total					60.8	781.8	842.6

(1) Quarterly during grace period.

(2) On December 31, 2002, Elektro, ETB and ENE Enron concluded negotiations with BCI to restructure this fixed rate note issued by ETB. The restructuring reduced interest expenses by $51 million on a present value basis and extended final maturity from December 2007 to December 2012. Under US GAAP, the resulting effective interest rate is 4.15%

(3) Starting in December 2007.

TJLP: Long term interest rate RGR: Correction index defined by Eletrobras. It has been kept flat since 1999.
IGPDI: Inflation rate SELIC: Basic interest rate CDI: Interbank interest rate

Under Elektro's $32 million Brazilian National Bank for Economic and Social Development credit facility used to fund its capital expenditures, it must maintain a capitalization ratio (shareholders' equity to total assets) above 40% during the amortization period of the loan. Because estimates indicate that Elektro will not be in compliance with this financial covenant, Elektro is attempting to renegotiate this covenant and is also seeking to resume drawdowns that were suspended following the filing of ENE's Chapter 11 Case. As a result of ENE's chapter 11 filing, Elektro had to cancel an $80 million local debenture placement in 2001, and all commercial banks called back any unused credit facilities ($37 million). The lack of a clear regulatory framework in Brazil, including the absence of an agreed methodology for the required periodic tariff review, the recent drop in electrical energy demand caused by the rationing program in 2001, and the high volatility and 52% foreign exchange devaluation recorded in 2002 have caused the financial markets to delay or reduce financings to most LDCs. Despite Elektro's current efforts to restore its credit facilities, there can be no assurances that Elektro will be able to raise new funding or refinance its current debt.

(M) Government Financing Program to LDCs. On September 16, 2003, the Brazilian National Bank for Economic and Social Development and the Ministry of Mines and Energy announced a R$3.0 billion (US$1 billion) financing program aimed at enhancing the LDC's capital structure. The program is available for both private and state-owned LDCs. Initial program eligibility requirements are: (i) renegotiation of at least 30% of short-term private bank loans; (ii) commitment of the LDC's controlling shareholders to convert all intercompany credits into equity; and (iii) meeting certain corporate governance standards set by the São Paulo Stock Exchange. The financing will be provided through the issuance of 10-year convertible debentures with a 4-year grace period. Elektro is currently assessing how it might participate in this program.

e. Power Generation. The table below identifies the power plants included in Power Generation and several of their key features.

Power Generation Power Plants

Business	Location	Expected Prisma Ownership Interest	Generating Capacity	Fuel Type	Date Commercial Operation Was Initiated	Percent Generating Capacity Contracted and Scheduled Termination Date Under Principal Power Purchase Agreements
Cuiabá – EPE	Brazil	50.0%	480 MW	Natural Gas	May 2002	100% until May 2019
Trakya	Turkey	50.0%	478 MW	Natural Gas	June 1999	100% until June 2019
PQP	Guatemala	37.5%	234 MW	Fuel Oil	February 1993 (110 MW) July 2000 (124 MW)	47% until February 2013
BLM	Panama	51.0%	280 MW	Fuel Oil	1967 (40 MW) 1971 (40 MW) 1973 (40 MW) 2000 (160 MW combined cycle)	Elektra – 30% until December 2003 Edemet - 48% until December 2004 Elektra – 29% from January 2005 until December 2008
SPC	Philippines	50.0%	116 MW	Fuel Oil	February 1994	100% until February 2009
ENS	Poland	100.0%	116 MW electrical 70 MW thermal	Natural Gas	June 2000	100% electrical until June 2020 85% to 90% thermal until June 2020
SECLP	Dominican Republic	84.1%	184 MW	Fuel Oil	August 1994	92% until January 2015
EEC	Nicaragua	35.0%	70.5 MW	Fuel Oil	September 1999	71% until September 2014
GMSA	Argentina	100.0%	70 MW	Natural Gas and Diesel Fuel	March 1995	Arcor - 9% until July 2004 (six power purchase agreements) CEMSA – 40% until July 2005
MEC	Guam	50.0%	88 MW	Fuel Oil	January 1999	100% until January 2019

As indicated in the table above, each of the plants that Prisma expects to be a part of its business has been completed and has initiated commercial operations. Refer to the project-specific sections below for more detailed descriptions of each of the Cuiabá Project, Trakya, PQP, BLM, SPC and the Other Power Generation Businesses.

(i) Cuiabá Integrated Project. The Cuiabá Project consists of four companies that on an integrated basis operate a power plant in Brazil and purchase natural gas in Bolivia or Argentina and transport it to Brazil for use as fuel in the generation of electrical energy at the power plant. EPE is a power generation company that operates an approximately 480-MW gas-fired, combined-cycle power plant located in Cuiabá, Mato Grosso, Brazil. GasBol is a gas transportation company that operates an approximately 226-mile 18-inch gas pipeline in Bolivia to transport natural gas from the Bolivian portion of the BBPL to the pipeline interconnection at the Bolivia-Brazil border. GasMat is a gas transportation company that operates an approximately 175-mile 18-inch gas pipeline in Brazil, which is interconnected to the GasBol pipeline at the Bolivia-Brazil border, to transport natural gas from the border to the EPE power plant. TBS is a gas supply company that purchases natural gas from Bolivian or Argentinean sources, arranges for transportation of the gas, including through GasBol and GasMat, and sells the gas to EPE. The Cuiabá Project sells all of the capacity of and energy produced by EPE to Furnas, one of Brazil's federally owned electricity generation companies.

(A) Shell Settlement Agreements. As of September 26, 2003, following the closing of the Shell Settlement and the equity transfers contemplated therein, Shell owns, through its affiliates, a 50% interest in each of EPE, GasMat, TBS, and GasBol. Several disputes arose between ENE and Shell relating to the development, construction, and operation of the Cuiabá Project and the management and governance of EPE, GasMat, GasBol, and TBS. Affiliates of ENE and Shell entered into a Definitive Agreement in June 2003 to resolve these disputes, and the Bankruptcy Court approved the Shell Settlement on August 7, 2003. The parties closed the transactions contemplated by the Shell Settlement on September 26, 2003.

The original projected aggregate capital cost of the Cuiabá Project was approximately $505 million. As a result of significant delays and cost overruns incurred by the construction contractor, an affiliate of ENE, the actual aggregate capital cost of the Cuiabá Project was approximately $740 million. To settle disputes related to these cost overruns, which were funded in part by Shell, various ENE affiliates transferred equity interests in each of EPE, GasMat, and TBS to affiliates of Shell in accordance with the terms and conditions of the Shell Settlement.

In connection with the Shell Settlement, certain affiliates of Shell and certain affiliates of ENE entered into a Master Voting Agreement to address the management and governance of the Cuiabá Project as well as ENE's and Shell's respective ownership interests in the BBPL and TRSA. The parties agreed to vote their respective equity interests together through the implementation of a supervisory board whose affirmative vote is necessary to approve certain substantial transactions of any Cuiabá Project company, including (i) certain expenditures in excess of $250,000, (ii) a transfer of all or a substantial part of the assets of any Cuiabá Project company, (iii) any amendment to the organizational documents of any Cuiabá Project company, (iv) any decision to incur indebtedness (except if for less than $250,000 in the aggregate), (v) the appointment, removal, elimination, creation or modification of all senior managers' positions, (vi) any decision appointing or removing the auditors of any Cuiabá Project company, and (vii) any other material transaction relating to the Cuiabá Project companies. The failure of the parties to agree on actions required for the operation of the Cuiabá Project could result in a deadlock that could have a material impact on the revenues and expenses of the Cuiabá Project.

Pursuant to the terms and conditions of the Shell Settlement, the revised organizational documents of each of the Cuiabá Project companies contain standard provisions relating to purchase rights triggered by a prospective change of control. In addition, the revised organizational documents provide for certain rights of first refusal and drag-along rights. For as long as a direct or indirect controlling equity holder of a Cuiabá Project company is not creditworthy, each other equity holder has drag-along rights with respect to the equity of a Cuiabá Project company held by the non-creditworthy equity holder. However, the exercise of such drag-along rights by a selling equity holder triggers the non-creditworthy equity holder's right of first refusal with respect to the equity of a Cuiabá Project company held by the selling equity holder. If an equity holder is required to sell its equity in a Cuiabá Project company, whether pursuant to a drag-along right or right of first refusal, then any debt associated with the selling equity holder's interests is required to be transferred to the purchaser of the equity to the extent that the selling equity holder controls the holder of the associated debt.

In accordance with the terms and conditions of the Shell Settlement, Shell transferred to affiliates of ENE an aggregate amount equal to $15.5 million. Approximately $4 million was used to provide a mezzanine loan to GTB. In connection with the Shell Settlement, certain affiliates of ENE and Shell released and discharged each other and each of the Cuiabá Project companies, and each of their respective agents and affiliates, from all claims with respect to the Cuiabá Project, subject to a limited indemnity, that arise out of acts or omissions occurring on or prior to the closing date of the Shell Settlement, including unasserted claims, with certain exceptions.

(B) Intercompany Debt. The Cuiabá Project does not have any third-party financing. However, EPE, GasMat, and GasBol borrowed an aggregate of approximately $475 million from affiliates of ENE and Shell during the period from October 1998 to October 2001 to finance construction. Pursuant to credit restructuring agreements among each of EPE, GasMat, and GasBol, on the one hand, and their respective ENE and Shell affiliate lenders, on the other hand, which were entered into as part of the Shell Settlement, each borrower will only be obligated to make payments on its loans from its cash flow that would otherwise be available after expenses, taxes, and reserves are paid. EPE is exposed to market risks, including changes in currency exchange rates between the Brazilian real and the U.S. dollar. EPE attempts to mitigate some of the negative impact of changes in exchange rates through various hedging mechanisms and treasury policies.

(C) Dividend and Distribution Policy. Except for TBS, none of the Cuiabá Project companies have distributed dividends and no distribution of dividends by EPE, GasMat, or GasBol is expected in the foreseeable future. Available cash is expected to be used solely for the repayment of ENE and Shell affiliate loans after certain reserves are funded. TBS distributed dividends from its 2001 and 2002 earnings and expects to distribute to its shareholders future available cash after reserve accounts are funded.

ENE expects to transfer its equity interests in its affiliates that made loans to EPE, GasMat, and GasBol to Prisma. However, the loans to EPE and GasMat were made by ENHBV, and there is a risk that ENE will not be able to transfer ENHBV to Prisma. Refer to Section X.A.2., "Risk Factors" for further information. If ENHBV is not transferred to Prisma, Prisma will not benefit from approximately $271 million in loans payable by EPE and GasMat.

(D) Plant and Equipment. EPE employees operate the power plant and provide operation and routine maintenance services. The combustion turbine generators used in the plant were two of the first model V84.3A turbines produced by Siemens. The Siemens turbines have experienced significant problems, including mechanical and technological problems with tiles in the combustion chamber and with premature failure of critical parts. Refer to Section XIV.I.2.a., "Uninsured Plant and Equipment Failures" for further information about the risks related to equipment failures.

The turbines were initially commissioned on diesel fuel prior to the completion of the two gas pipelines that transport natural gas to EPE. In connection with the changeover of the power plant to natural gas, one of EPE's two combustion turbines suffered a catastrophic failure and had to be repaired at a cost of approximately $22 million. EPE's insurers have resisted payment of EPE's claim for this loss. EPE does not have a long-term contract for major maintenance and periodic overhauls of its combustion and steam turbine generators; instead, the Cuiabá Project currently contracts for major maintenance services on a per-overhaul basis. EPE is negotiating a long-term major maintenance service agreement with Siemens, but if an agreement is not reached, EPE may not be able to obtain major maintenance services at the necessary times or for appropriate prices, and in either case the Cuiabá Project's profitability may be negatively impacted.

The catastrophic failure of EPE's Siemens turbine in August 2001 has impacted EPE's ability to secure adequate, affordable insurance coverage. EPE's insurance premiums have increased significantly since mid-2001, and the deductible amount under EPE's policies for property damage has increased significantly.

GasMat's and GasBol's pipelines each run through environmentally sensitive parts of Brazil and Bolivia. Several environmental groups and non-governmental organizations carefully watch the Cuiabá Project's pipeline operations, and have in the past alleged violations of environmental, health and safety laws and policies, and GasMat and GasBol must respond to these allegations. In addition, affiliates of ENE and Shell have agreed to contribute up to $20 million over a 15-year period to the Chiquitano Forest Conservation Project in Bolivia. Pursuant to the terms of the Shell Settlement, TBS will provide the funds to pay the Chiquitano Project obligations of both the ENE and Shell affiliates.

(E) Furnas PPA. EPE relies on a single customer, Furnas, to purchase all of the capacity and associated energy of the power plant. The PPA between Furnas and EPE has a 21-year term ending in 2019 and provides the sole source of revenues for the Cuiabá Project. The obligations of Furnas under the PPA are guaranteed by Eletrobras, the Brazilian state-owned electric company. If Furnas fails to fulfill its contractual obligations, the Cuiabá Project's financial results will be materially adversely affected, as the Cuiabá Project would likely be unable to find another customer for EPE with similar pricing. Refer to Section XIV.I.2.c., "Concentration of Customers and Suppliers" for further information about the risks of relying on a limited number of customers.

Pursuant to the PPA, EPE has committed to sell its entire capacity and associated energy to Furnas in exchange for a monthly payment in reais from Furnas based on the guaranteed available capacity and the delivered energy. If Furnas requests that EPE be dispatched above the guaranteed capacity, Furnas must pay an increased capacity component. The PPA provides for three tariff adjustment mechanisms: (1) an annual adjustment to the tariff for Brazilian inflation, (2) an adjustment for the gas-related components of the tariff if there is a cumulative devaluation or appreciation of the Brazilian real against the U.S. dollar of 5% or more, and (3) an adjustment to the tariffs based on an economic-financial disequilibrium of the PPA. In accordance with the tariff adjustment provisions, EPE has made five requests to Furnas since May 2001 to adjust the power sales price for economic-financial disequilibrium, but Furnas has failed to respond to EPE's requests. Additionally, EPE and Furnas have not agreed on the basis for the inflation adjustment to the tariff. However, the gas-related component of the tariff adjustment is working according to the terms of the PPA. If Furnas continues to refuse to fully adjust the price of capacity and power sales under the PPA, EPE may have to pursue arbitration proceedings to enforce its contractual rights.

Rationing and conservation programs in Brazil during 2001 and 2002 resulted in significant reductions in electricity demand. High rainfall levels during the 2002 rainy season led to the end of mandatory rationing in February 2002, and there is still a current surplus of electric capacity in Brazil. Because the PPA has a significant U.S. dollar basis and is designed to allow a return on a U.S. dollar investment, the substantial devaluation of the Brazilian real against the U.S. dollar in 1999 and 2002 increased the cost of the Cuiabá Project's electric power to Furnas relative to Furnas's other contracts or sources that are not U.S. dollar-based. Furnas must generally pay capacity payments under the PPA whether or not the power plant is dispatched. These capacity payments comprise approximately 96% of the revenues under the PPA. The combination of these factors may create an incentive for Furnas to seek to renegotiate or otherwise not perform its payment obligations under the agreement. In a speech in March 2003, the president of Eletrobras criticized the role of free markets in the Brazilian power sector and stated that most power contracts would remain unchanged, except for extreme cases in which Eletrobras will pursue renegotiations. If EPE were forced to renegotiate a new contract to sell its power in the current market, the sales price would likely be significantly lower than the current contractual price. Refer to Section XIV.I.1.c., "Political Instability, Civil Unrest, and Regime Change" for further information.

Furnas has the contractual right to terminate the PPA for various reasons, including default, bankruptcy of EPE, dissolution of Furnas, or a force majeure event that lasts for more than 12 consecutive months. Upon a termination of the agreement, Furnas has certain rights and obligations to purchase EPE and the associated electric transmission systems up to the delivery points. At the end of the term of the PPA, Furnas has the right to purchase the EPE facilities at a nominal purchase price calculated based on the tariff in effect during the final year of the PPA term. The parties may adjust the purchase price for additional capital improvements to the plant and related depreciation. If Furnas terminates the PPA due to a default by EPE, Furnas has the right to purchase the EPE facilities for an amount equal to the lesser of (i) a price based on 80% of the present value of the guaranteed capacity payments remaining in the term of the agreement and (ii) the determined market value of the EPE facilities. If EPE terminates the PPA due to a default by Furnas or Eletrobras, EPE has the right to require Furnas to purchase the EPE facilities for an amount equal to the greater of (i) a price based on 100% of the present value of the guaranteed capacity payments remaining in the term of the agreement and (ii) the determined market value of the EPE facilities.

(ii) Trakya Elektrik Uretim Ve Ticaret Anonim Sirketi (Trakya). ENE, together with Whitewing LP, owns an indirect 50% equity interest in Trakya. Trakya owns and operates a combined cycle gas turbine power plant with a nominal capacity of 478 MW located on the northern coast of the Sea of Marmara near Istanbul, Turkey. The other equity participants in the project are Midlands with a 31% interest, Wing International, Ltd. with a 9% interest, and Gama with an aggregate 10% interest. Trakya sells all of the plant's capacity and energy to the state-owned TETAS under an Energy Sales Agreement.

The plant consists of two combustion turbine generators designed to run on natural gas or distillate fuel oil, two heat recovery system generators, and one steam turbine generator. The plant commenced commercial operations in June 1999. During 2002, the plant suffered a three-month outage to allow for repairs to the steam turbine rotor, which had been damaged due to excessive vibration. Refer to Section XIV.I.2.a., "Uninsured Plant and Equipment Failures" for further information about the risks related to equipment failures.

The plant was built and is owned and operated pursuant to an Implementation Contract between Trakya and the Ministry of Energy. The Implementation Contract has an initial term ending in June 2019, which may be extended if certain conditions are satisfied. There is no guarantee that the conditions for extension will be satisfied or that the contract will be extended. Upon expiration of the Implementation Contract, the plant will be transferred to the Turkish Ministry of Energy free of charge.

Turkey adopted the 2001 Electricity Market Law, which was intended to introduce a free market for the generation, transmission, trading, and distribution of electricity in Turkey. The law also created an independent regulatory body, the Energy Market Regulation Agency, to oversee the energy and natural gas markets in Turkey. In August 2002, the Energy Market Regulation Agency issued a regulation that requires private power generators, including Trakya, to apply for a generation license by June 2003 and to pay an annual license fee. Trakya has applied for this license, but there is no assurance that the license applied for will be granted. While the new regulation does not specifically reject or amend existing private power generation contracts, including the Implementation Contract and the Energy Sales Agreement, it also does not explicitly grant an exemption to existing operators or provide that existing contractual rights prevail in the event of any conflict. Refer to Section XIV.I.1.b., "Regulatory Intervention and Political Pressure" for general information about the risks related to regulatory intervention. Trakya sought to have the Turkish administration court set aside the regulation on the basis that it does not protect the vested rights of Trakya by filing a lawsuit and a request for injunctive relief. Trakya's request for injunctive relief has been denied, along with its appeal of the denial. The case on the merits of the lawsuit is still pending.

The Energy Market Regulation Agency has also expressed its desire to renegotiate the terms of existing agreements with the build-operate-transfer (for this section only "BOT") electric plants in Turkey, including Trakya. In addition, conflicting Turkish newspaper reports in 2003 have indicated that the Turkish government is considering alternatives to deal with Trakya and the other BOT plants, including renegotiation of contracts, early buyouts or other actions. According to these reports, the government is contemplating these actions out of the belief that the BOT plants sell power at rates that are unacceptably high. To date, Trakya has not received any notification of any such action from the Energy Market Regulation Agency or other instrumentality of the Turkish government.

In October 2003, Trakya received an audit report from the regional Turkish tax office claiming approximately US$138 million due from Trakya in unpaid taxes, penalties and penalty interest. Among other findings, the audit report claimed that certain development costs, fees, bonuses and subordinated debt payments improperly applied an investment allowance granted to the project and that Trakya improperly revalued its depreciable fixed assets. Trakya has consulted with its accountants who have advised that the tax audit report contains a number of quantitative mistakes and misapplies in certain instances the relevant tax legislation. Trakya is in the process of challenging the findings of this audit and the claims of underpayment. While it cannot predict the ultimate outcome, Trakya believes that it has good defenses to such claims and intends to pursue them.

(A) Shareholder Arrangements. Trakya's board of directors consists of seven interested members, of which the ENE shareholder appoints three and the other shareholders appoint four. In addition, two independent members are selected by all of the shareholders. Transfers of shares of Trakya are subject to shareholder approval under Trakya's articles of association and shareholder agreement. Further, ENE, Midlands Electricity Plc, The Wing Group, Ltd., and Gama have entered into a Sponsors' Agreement that includes minimum ownership requirements applicable to ENE, Midlands Electricity Plc, and The Wing Group, Ltd. Profits available for distribution to shareholders must first be used to pay corporate taxes and to meet Trakya's obligations and the minimum applicable reserve requirements under Turkish law and the Trakya senior loan agreements.

(B) Customer. All of the capacity and energy produced by the plant is sold to TETAS under the Energy Sales Agreement that is governed by Turkish law. TETAS's payment obligations under the agreement are guaranteed by the Republic of Turkey. Refer to Section XIV.I.2.c., "Concentration of Customers and Suppliers" for further information about the risks related to reliance on a limited number of customers.

The Energy Sales Agreement provides for a tariff primarily expressed and paid in U.S. dollars based on a take-or-pay structure with fixed and variable capacity and energy components. The tariff was originally intended to allow for the recovery of fixed capital costs, servicing of debt, payment of operation and maintenance costs, a pass-through of fuel costs, and a return on investment. The Energy Sales Agreement has an initial 20-year term, expiring in June 2019, which may be extended on the same terms as the Implementation Contract. As with the Implementation Contract, there is no guarantee that the conditions for extension will be satisfied or that the agreement will be extended.

In 2000 and 2001, Trakya did not receive timely payments under the Energy Sales Agreement and faced a dispute over what exchange rate to apply to overdue payments. Trakya's position prevailed, and TETAS has paid all disputed amounts with the exception of certain delay interest that is still outstanding. No assurance can be given, however, that future payment problems and related disputes, which could be triggered or exacerbated by further devaluation of the Turkish lira, will not adversely affect Trakya's results of operations. Refer to

Section XIV.I.1.d., "Devaluations of Foreign Currencies" for further information about the risks related to currency devaluations.

(C) Supplier. Natural gas is the plant's primary fuel source and is provided by BOTAS under a take-or-pay Gas Sales Agreement governed by Turkish law with an initial term ending in October 2014. The take-or-pay obligation under the Gas Sales Agreement is based on an approximate level of gas consumption that would be required for Trakya to meet most of its annual net generation requirements under the Energy Sales Agreement. The natural gas purchased under the agreement is priced according to a U.S. dollar-based formula, but payments are made in Turkish lira. BOTAS's payment obligations under the agreement are guaranteed by the Republic of Turkey. Refer to Section XIV.I.2.c., "Concentration of Customers and Suppliers" for further information about the risks related to reliance on a limited number of suppliers.

(D) Associated Debt. The total cost of the plant was approximately $556.5 million and was funded with $417.3 million in senior secured loans set to mature in September 2008, $23.8 million in subordinated shareholder loans set to mature in September 2005, and $115.4 million in equity.

The senior secured loans consist of (1) a $225.1 million loan from Eximbank at a fixed interest rate of 7.95%, (2) an $84.0 million loan from OPIC at a fixed interest rate of 9.803% and (3) a $108.2 million loan from BLB with a floating interest rate that was fixed at 7.8963% by a swap agreement. As of June 30, 2003, the outstanding balances on the Eximbank, OPIC, and BLB loans were approximately $137.5 million, $51.3 million, and $66.2 million, respectively.

The senior debt is secured by Trakya's assets and shares and requires Trakya to establish debt service and other cash reserves currently totaling nearly $100 million. The senior loan agreements also place restrictions on shareholder distributions, payments on subordinated indebtedness, and transfers of shares in Trakya.

Approximately $17.8 million in subordinated shareholder loans remained outstanding as of June 30, 2003. The subordinated loans accrue interest at the rate of 13% per year.

(E) O&M Agreement. O&M services for the plant are provided under a long-term O&M Agreement by an operator consortium composed of two ENE affiliates. Trakya pays an annual fee equal to $500,000 in 1998 dollars indexed to the U.S. Consumer Price Index. The obligations of the consortium are guaranteed by ACFI up to a cap of $1.25 million in 1998 dollars indexed to the U.S. Consumer Price Index and further supported by a letter of credit in the amount of the guarantee cap. The bankruptcy of ACFI has resulted in a default under the senior debt and could result in the termination of the O&M Agreement absent a waiver by Trakya and the lenders. It is contemplated that, subject to receiving the requisite consents and a waiver of the default caused by the ACFI bankruptcy, the operator consortium will be transferred to Prisma, and Prisma will provide replacement credit support for the operator consortium's obligations.

(iii) Puerto Quetzal Power LLC (PQP). ENE owns an indirect 37.5% equity interest in PQP, a Delaware limited liability company that owns 234 MW of effective generation capacity in two facilities located on the Pacific Coast at Puerto Quetzal, Guatemala, 75 kilometers south of Guatemala City. The combined 234 MW output provided about 16% of Guatemala's installed electric capacity in 2002. The other equity participants in the project are Centrans Energy Services, Inc. with a 37.5% interest, and CDC Holdings (Barbados) Ltd. with a 25% interest. Under PQP's operating agreement, most decisions of the members are made by majority vote, while certain extraordinary decisions require unanimous consent. Deadlocks may be resolved by a buy/sell process, and certain transfers of interests trigger a right of first refusal. PQP owns 100% of Poliwatt, its power marketing arm, and Pacific Energy Financing Ltd.

The PQP facilities are sited, and obtain certain services, pursuant to a Contract for Harbor Services and Leasing of Areas with Empresa Portuaria Quetzal. Enron Servicios Guatemala Ltda., a Guatemala-based company, operates and maintains the PQP facilities pursuant to two O&M agreements and provides marketing support to PQP and to Poliwatt pursuant to two administrative and commercial support agreements. Enron Servicios Guatemala Ltda. is a wholly owned affiliate of ENE, and ENE expects to transfer it to Prisma. Glencore AG provides fuel for the facilities pursuant to a fuel supply agreement expiring in February 2013.

(A) Plant and Equipment. PQP's first plant, commissioned in February 1993, consists of 20 Wärtsilä 18V32D heavy fuel oil-fired generator sets with an effective capacity of 110 MW mounted on two barges (Enron I and Enron II), and related onshore facilities. The second plant, located next to the first and commissioned in July 2000, consists of 7 heavy fuel oil-fired MAN B&W 18V48/60 generator sets with an effective capacity of 124 MW mounted on one barge (Esperanza), and related onshore facilities. A generator in the first plant experienced an electrical failure in December 2002 and was replaced. A second generator experienced a similar failure in July 2003 and is expected to be replaced by September 2003. PQP's eight other generators made by the same manufacturer are undergoing inspection and will likely require repairs. The second plant, which represents a new MAN design, has experienced engine problems for which solutions have been implemented. However, the long-term effectiveness of these solutions cannot be guaranteed.

(B) Market and PPA. PQP has been supplying power since 1993 to EEGSA under a PPA for 110 MW of capacity and a 50% take-or-pay energy obligation. The 20-year term of the PPA ends in February 2013. The original PPA was physical and required that the capacity and energy be delivered from PQP's installations (Enron I and Enron II). In September 2001, the parties modified the agreement by converting it to a financial instrument through which PQP complies with its supply obligations from its installations, contracts with third parties, or the spot market. As of December 2002, the PPA accounted for approximately 51% of PQP's revenues. EEGSA has complied with its payment obligations under the agreement. However, PQP understands that EEGSA has been experiencing liquidity problems and has been unable to pay certain suppliers in a timely fashion. The failure of EEGSA to make full and timely payments to PQP would adversely impact PQP cash flow and could result in PQP defaults on its contractual payment obligations to third parties and under its loan agreements.

PQP has also been supplying power in the Guatemala and El Salvador markets, under short- and medium-term sales agreements (which generate 31% of PQP's revenue) and spot market sales (which generate 18% of PQP's revenue), made directly or through Poliwatt. Poliwatt's market also includes wholesale customers such as local distribution companies, marketers, and generators, and large end-users that do not use an intermediary to buy their energy. Poliwatt does not operate as a separate profit center, but passes through to PQP all revenues received from its power marketing activities, net of costs.

A portion of PQP's output is exposed to merchant market risk. In the absence of contracted sales, in a market in which margins on spot power sales may be volatile as driven not only by basic supply and demand, but also by fuel prices and hydrological conditions, PQP may not be able to sell its merchant power output at prices that provide sufficient revenues to generate any profit margin.

(C) Associated Debt. In December 2000, PQP closed a $123 million senior secured debt refinancing with OPIC and MARAD, which provided funding for the Esperanza plant and paid off the outstanding amount of the initial International Finance Corporation funding for the Enron I and II plants. The term of the debt is 12 years and the principal amortizes in 23 equal installments commencing in June 2001. The debt is secured by all PQP project assets and revenues, by a pledge of all of the member interests in PQP, by cash collateral in several reserve accounts, and by various ENE and Poliwatt guarantees. ENE's support includes capped guarantees of principal and interest payment shortfalls. The principal component of this support was structured to cover the period between the expiration of the original EEGSA PPA and the OPIC and MARAD loan maturities.

ENE's bankruptcy caused a default under the loan documents. Pending the conclusion of negotiations among the lenders, PQP and the sponsors regarding the provision of substitute security to replace the ENE support, the lenders have exercised their rights to trap distributions from PQP and have withheld certain payments from PQP to member affiliates. Although the lenders have not expressed a desire to exercise remedies, they have the right to accelerate payment of the outstanding debt and foreclose on the PQP assets, including applying reserves and trapped cash to the paydown of outstanding loans. In addition, due largely to changes in the insurance market, PQP has been unable to procure on commercially reasonable terms the insurance coverages required by the senior lenders. If OPIC or MARAD refuses to grant a waiver of PQP's failure to obtain such coverages, either lender may assert a default under the loan agreements. OPIC has already requested that PQP fund a $1.5 million insurance reserve out of project cash flow to cover exposure to increased deductibles. There can be no assurances that PQP will be able to cure these defaults.

(D) Regulatory Environment. In Guatemala and El Salvador, generators sell electricity through (1) contracts with distributors, large consumers, generators and marketers or (2) the spot market (domestic or regional). In both countries, in order to participate in the spot market, the participants have to submit sufficient guarantees to cover their performance and payment obligations; however, the market is open to competition. The spot market in Guatemala will dispatch the generation company with the most efficient costs of operation based on weekly-declared costs. The spot market in El Salvador bases its dispatch order on the generators' daily-price bids. Neither Guatemala nor El Salvador has a spot market for capacity, in the sense that generators do not receive a capacity payment from the wholesale market. However, because the Salvadorian spot market is based on price declarations, the capacity payment is included implicitly in the price. In Guatemala, distribution companies are required to contract 100% of their demand and will recover generation costs based on the average of the previous quarter purchasing prices. In El Salvador, distribution companies are not required to contract their demand and are entitled to recover generation costs equivalent to the spot market price.

Due to the merit order dispatch method employed in the Guatemala and El Salvador power markets, the introduction of newer or more cost efficient power plants (including those which can operate on lower cost fuels) could reduce power sales opportunities and margins for PQP. At least one competitor is investigating utilizing a lower cost fuel, the feasibility of which remains to be proven, at a 100MW+ power generation facility located in the region.

Deterioration in Guatemala's political and general business environment in 2002 has increased political instability and financial burdens for the government, which may seek to lower electricity costs by renegotiating private sector PPAs. However, any government-imposed or mandated modification to the PPA would constitute a drastic change in the legal framework governing the electricity sector and therefore would be subject to political and constitutional challenges.

Initiatives have been undertaken to expand the membership of the market regulator (Comision Nacional de Energia Elétrica), which could result in the increased politicization of that important regulatory body.

(E) U.S. Senate Committee on Finance. On February 15, 2002, the Senate Finance Committee announced that it would conduct an investigation of ENE's tax and compensation matters. As part of that inquiry, it re-opened an investigation of substantially the same tax transactions involving PQP that the United States Tax Court dismissed, and the DOJ and the SEC previously reviewed in 1997-1999. Although those agencies brought no charges and assessed no penalties against ENE or PQP, the Committee referred its report to the DOJ in March 2003. No charges or penalties have resulted from the referral.

In August 2003, following publication of the Senate Finance Committee's report, the Guatemalan Congress issued a recommendation that called upon EEGSA, the counterparty to PQP's PPA, to cancel its contracts with PQP. The recommendation also requested the executive branch to consider whether the PPA, or its execution or amendment with EEGSA, may have been harmful to state interests.

The ultimate impact of the recommendation is unclear; however, local counsel advises that the recommendation is not legally binding and does not obligate any party to take any action. Counsel further advises that applicable law may not permit EEGSA to invalidate or rescind the PPA, or permit the executive branch to conclude that the PPA is harmful to state interests. PQP is considering its legal options to ensure that the PPA remains valid and enforceable.

(F) Tax Matters. The fuels utilized by PQP for power generation are exempt from distribution and import taxes. From time to time, the government has initiated efforts to repeal these exemptions, in particular the distribution tax. Losing the distribution tax exemption would result in a significant increase in annual bunker fuel costs. Although PQP may recover a portion of these cost increases from EEGSA or pursuant to the spot market rules, there is no guarantee that PQP would be able to do so. The remainder of the cost increases would have to be passed on to other PQP customers.

(iv) Bahia Las Minas Corp. (BLM). ENE (through EIPSA and EC III) owns approximately an indirect 51% equity interest in BLM. BLM owns and operates a power generation complex with an aggregate installed capacity of 280 MW. The power generation complex is located on the Caribbean coast, in Cativá, Province of Colón, Panama. The Government of Panama owns approximately a 48.5% interest in BLM and former and present employees hold the remaining interests as common stock or preferred stock.

The first plant, commissioned in phases between 1967 and 1973, consists of a power block comprised of three heavy fuel oil-fired boilers that power three steam turbine generators with a total installed capacity of 120 MW and related facilities. The second plant, commissioned in two phases in 1988 and 2000, consists of a combined-cycle power block comprised of three marine diesel fuel oil-fired combustion turbine generator sets and one steam turbine generator set, with a combined installed capacity of 160 MW. In 2002, BLM provided approximately 20% of the electricity generation (and approximately 58% of all thermally generated energy) in Panama. BLM operates the plants under a 40-year generation license granted on December 14, 1998.

BLM has been supplying power since October 1998 to two distribution companies in Panama under PPAs for 83 MW and 135 MW, respectively, of capacity and associated energy. As of December 2002, existing PPAs under contract collectively accounted for approximately 95% of BLM's revenue. The 83-MW agreement terminates in December 2003 and the 135-MW agreement terminates in December 2004. In 2002, BLM was awarded a new 80-MW PPA with a four-year term commencing in January 2005. BLM has also been supplying power in the spot market which, as of December 2002, represented approximately 2% of BLM's revenue. Bids for new contracts will take place in November 2003. The pricing and terms and conditions under the two original contracts, which will expire in 2003 and 2004, are more favorable to BLM than those being currently offered by the distribution companies. If BLM is not able to enter into replacement contracts, it would sell most of its energy in the spot market, and because BLM may not always be the lowest-marginal cost thermal producer, it may not have sufficient margin to meet its financial and operational obligations.

The BLM facilities are located on land owned by BLM near the city of Colón on the Caribbean side of Panama. BLM also owns 7.6 acres of commercial land in Panama City, which is currently for sale. EPMS provides administration and management oversight services to BLM under a contract that expires in 2019. Fuel requirements are fulfilled through spot market purchases. Market risk exposure to fuel price risks is partially mitigated through fuel escalation clauses in the PPAs.

As of June 30, 2003, BLM had approximately $53.9 million in long-term third-party debt outstanding, all of which is unsecured, with approximately $12.8 million due at maturity or upon scheduled amortization within the following 12 months. Maturity of its long-term loans will occur in 2006 and 2007. BLM might be required to pay penalties to the Government of Panama if it fails to repay or refinance certain of its long-term debt obligations by January 2004. BLM has twice obtained one-year extensions of this obligation and will try to secure another extension. Pursuant to its revolving credit facility, BLM may not declare or distribute any dividends except under limited circumstances until the facility is repaid. Further, BLM is required to reduce the revolving line of credit from $13.5 million to $12.0 million on December 15, 2003 and is currently negotiating with the lender to restructure this reduction.

BLM's revenues in the years 1999 through 2001 and then again in 2003 decreased significantly as a result of certain regulatory decisions. Refer to Section X.C.6., "BLM" for further information. BLM has challenged the fairness of these decisions and claimed that it is owed additional revenues in excess of $10 million. The outcome of these claims is uncertain. If BLM fails to recover the lost revenues resulting from the regulatory decisions or fails to win an increase in contract revenues, then BLM may not have sufficient cash to make future payments due under its loan agreements. In addition, BLM will be required to post bonds when it bids for new power sales agreements. BLM is presently working with local surety providers and certain lenders participating in the existing revolver facility to arrange for bonds and/or lines of credit necessary to meet any bonding requirements for new PPAs. Part of such arrangement may include the pledging of the BLM land listed for sale as security for the letter of credit or bond issuer.

(v) Subic Power Corp. (SPC). ENE owns an indirect 50% interest in SPC. Various entities of the Yuchengco Group of Companies, a diversified business group headquartered in the Philippines, own in the aggregate the remaining 50% of the interests in SPC. SPC owns and operates the Subic Project, a 116 MW diesel power generating facility located at the Subic Bay Freeport Zone, Olongapo City, on Luzon Islands, the Philippines.

The Subic Project commenced commercial operations in February 1994. SPC operates and sells the capacity and energy from the Subic Project under a Build-Operate-Transfer Agreement with the National Power Corporation of the Philippines. The operating parameters under the agreement call for the Subic Project to be utilized as a baseload plant. Under the terms of the Build-Operate-Transfer Agreement, the National Power Corporation supplies at its cost all fuel required for the generation of electricity by the Subic Project and assumes the risk associated with fuel pricing and delivery. The Republic of the Philippines has provided a Performance Undertaking to SPC affirming and guaranteeing the National Power Corporation's obligations under the agreement.

Upon expiration of the 15-year term of the Build-Operate-Transfer Agreement in February 2009, the Subic Project is to be turned over to the National Power Corporation free of charge. If certain events occur before the scheduled transfer date, the National Power Corporation will be required to buy out the Subic Project at a price set forth in the agreement.

Substantially all of SPC's revenue is derived from selling the entire capacity and generated electricity output of the Subic Project to the National Power Corporation. The tariff under the Build-Operate-Transfer Agreement is computed from a formula that contains capacity, fixed O&M and energy components. The tariff is intended to allow for the recovery of fixed capital costs and O&M costs, and a profit margin. The tariff also contains bonus and penalty provisions relating to the Subic Project's heat rate.

The site for the Subic Project is owned by the Subic Bay Metropolitan Authority, which leases it to the National Power Corporation. The National Power Corporation subleases the site to SPC for a term that coincides with the Build-Operate-Transfer Agreement. The Subic Project is operated and maintained by SPC personnel with technical supervision services provided by Enron Subic Power Corp. and advisory services provided by Enron Power Philippines Operating Corp., both of which are expected to be transferred to Prisma.

The total cost of developing and constructing the Subic Project was approximately $132 million, not including capitalized financing costs. The corporate shareholders of SPC made shareholder advances and equity contributions in proportion to their shareholding in a total amount equal to approximately $27 million. SPC issued Senior Secured Notes in an amount equal to $105 million to finance the remainder of the cost of the Subic Project. The notes are non-recourse to the shareholders, bear interest at 9½% per annum and are payable in semi-annual installments of principal and interest through December 2008. The outstanding balance of the notes as of June 30, 2003 was approximately $39.8 million. The noteholders have the right to sell their notes to SPC if ENE ceases to beneficially own at least 25% of the voting stock of SPC or if anyone other than ENE or an affiliate of ENE becomes responsible for the obligations of the operators under their respective operations and maintenance agreements. As of June 30, 2003, SPC also owed approximately $3.5 million to Enron Power Operating Company under an unsecured subordinated note for a performance bonus owed to Enron Power Operating Company for construction of the Subic Project.

The Philippine Bureau of Internal Revenue made income tax assessments on SPC for the years 1994, 1996, and 1997, which SPC has contested in the Philippine court of tax appeals. The amounts of these assessments were approximately Ph₱70 million (for 1994), Ph₱40 million (for 1996) and Ph₱10 million (for 1997). In May 2003, the court of tax appeals ruled in favor of the Philippine Bureau of Internal Revenue with respect to the 1994 assessment and found SPC liable for approximately Ph₱120 million (approximately $2.25 million) in unpaid taxes plus delinquency interest. SPC has filed a motion for reconsideration of the ruling, but there is no assurance that SPC will prevail in such motion or on the 1996 and 1997 assessments, or that the Philippine Bureau of Internal Revenue will not make additional income tax assessments for other years. SPC intends to seek a compromise settlement with the Philippine Bureau of Internal Revenue with respect to these three tax cases.

(vi) Other Power Generation Businesses. ENE's remaining power generation businesses are:

ENS, which owns a gas-fired cogeneration plant located in Poland with 116 MW of electric capacity and 70 MW of thermal capacity, and sells power to Polskie Sieci Electroenergetczne, the state-owned grid company, and steam primarily to Zaklady Chemiczne Organika – Sarzyna, a neighboring chemicals production facility;

SECLP, which owns a 184 MW fuel oil-fired, barge-mounted power plant located in the Dominican Republic and sells power to Corporacion Dominicana de Electricidad;

EEC, which owns a 70.5 MW fuel oil-fired power generation facility located in Nicaragua and sells power to Disnorte and Dissur, distribution companies owned by the Spanish group Union Fenosa;

GMSA, which owns a 70 MW gas and diesel-fired combined cycle power plant located in Argentina and sells power in the spot market and under PPAs with Arcor and CEMSA; and

MEC, which owns an 88 MW slow-speed diesel-fired power generating facility located in Guam and sells power to the Guam Power Authority.

The table below summarizes the outstanding indebtedness of ENS, SECLP, EEC, and MEC. Each of the loans, other than ENS's subordinated loans, are secured by the assets of the respective company.

Business	Debt Facility	Original Principal Amount ($)	Outstanding Balance as of June 30, 2003 ($)	Maturity Date(s)
ENS	Senior secured term loans split into 2 tranches	118.5 million	106.2 million	2015
	Subordinated term loans	12.75 million	5.5 million	Open
SECLP	Term loans split into 10 tranches	153.25 million	61.1 million	Between 2004 and 2008
EEC	Title XI bonds	50 million	37.5 million	2010
MEC	Term loans split into 2 tranches	135.4 million	126.7 million	2014 and 2017

ENS is in technical default under its senior secured debt facility due to a delay in reaching final plant completion until May 2003. ENS is seeking a waiver of this default. SECLP has received a notice of default under its debt facility because it has historically been unable to service its debt on a timely basis due to operating and design problems and substantial payment delinquencies by the off-taker under the PPA. SECLP's problems with its off-taker appear to be symptomatic of larger liquidity issues facing the off-taker, and the problems have forced the SECLP facility to cease operations on a number of occasions since 1999. EEC and MEC have received notices of default under their respective debt facilities because of ENE's bankruptcy. Defaults under each of these debt facilities give the project lenders the right to prohibit dividend payments, accelerate payment of the outstanding debt, and foreclose on the project assets.

The termination dates for the principal PPAs executed by ENS, SECLP, EEC, and MEC range from 2014 to 2020. The ENS PPA is at risk for an early termination, however, because the Polish government has proposed a restructuring of the electricity sector to facilitate competition, which may lead to the termination of all long-term PPAs between generators and Polskie Sieci Electroenergetczne.

The prices for electricity or steam sold under the principal off-take agreements executed by ENS, SECLP, EEC, and MEC are contractually established in the agreements. However, the Polish regulator imposed specified prices for electricity sold by ENS from June 2000 until July 2001 and continues to regulate prices for steam sold and fuel purchased by ENS. Furthermore, not all off-takers consistently meet their payment obligations. As discussed above, SECLP's off-taker has been delinquent in making payments under its PPA. In addition, two local utilities that have entered into a PPA with EEC and from which EEC derives approximately 86% of its revenues have recently failed to make payments to EEC and other suppliers in a timely manner.

GMSA was financed entirely with equity capital contributed by ENE. Approximately 44% of GMSA's revenue is derived from sales of capacity and spot electricity in the wholesale electricity market, while approximately 42% of its revenue is derived from a PPA with CEMSA set to expire in July 2005 and approximately 14% of its revenue is derived from six PPAs with Arcor set to expire in July 2004. GMSA obtains its fuel requirements under a gas supply agreement set to expire in December 2004.

MEC's generation facility was developed on a build, own, operate and transfer basis under a 20-year Energy Conversion Agreement that expires in January 2019, at which time MEC must transfer its facility to the Guam Power Authority free of charge.

B. Projections and Valuation

1. Projections

In conjunction with formulating the Plan, as set forth on Appendix K: "Prisma Financial Projections – 2004-2006", financial projections have been prepared for Prisma for the three years ending December 31, 2006. The projections are based on a number of assumptions made with respect to the future operations and performance of Prisma and should be reviewed in conjunction with a review of the principal assumptions set forth on Appendix K: "Prisma Financial Projections – 2004-2006". While the projections were prepared in good faith and the Debtors believe the assumptions, when considered on an overall basis, to be reasonable in light of the current circumstances, it is important to note that the Debtors can provide no assurance that such assumptions will be realized and Creditors must make their own determinations as to the reasonableness of such assumptions and the reliability of the projections. Refer to Section XIV., "Risk Factors and Other Factors to be Considered" for a discussion of numerous risk factors that could affect Prisma's financial results.

2. Valuation

Also in conjunction with formulating the Plan, the Debtors determined that it was necessary to estimate the post-confirmation equity value of Prisma. Accordingly, Blackstone and the Debtors formulated such a valuation, which is utilized in the Blackstone Model. Such valuation is based, in part, on the financial projections prepared by Prisma management and included in Appendix K: "Prisma Financial Projections – 2004-2006". This valuation analysis was used, in part, for the purpose of determining the value of Prisma to be distributed to Creditors pursuant to the Plan and to analyze the relative recoveries to creditors under the Plan.

It is important to note that the valuation assumes that all assets contemplated for transfer to Prisma are in fact transferred. If for any reason one or more assets are not transferred to Prisma, or one or more additional assets are transferred to Prisma, then the value could fluctuate and such fluctuations could be material.

a. Estimated Value. Based upon the methodology described below, the Blackstone Model utilizes an estimated equity value of $815 million, as the mid-point within a valuation range of $713 million to $918 million for Prisma at December 31, 2003. Therefore, assuming 40 million shares of new Prisma Common Stock will be issued and distributed to or on behalf of Creditors pursuant to the Plan, the value of such stock is estimated to range from $17.83 to $22.95 per share; provided, however, that such estimate does not reflect any dilution resulting from any long-term equity incentive compensation plan(s) as may be adopted by Prisma. However, it is anticipated that the impact of any such plan(s) to be adopted by PGE, CrossCountry and Prisma will, in the aggregate, represent less than 1% of the overall value to be distributed under the Plan. In addition, the valuation of Prisma does not include the anticipated costs associated with the voluntary termination of the ENE Cash Balance Plan. The estimated value is based upon a variety of assumptions, as referenced below under "Variances and Risks," deemed appropriate under the circumstances. The estimated value per share of the Prisma Common Stock may not be indicative of the price at which the Prisma Common Stock will trade when and if a market for the Prisma Common Stock develops, which price could be lower or higher than the estimated value of the Prisma Common Stock. Moreover, management of Prisma believes that there could be a material increase in value if (i) the markets view Prisma as a publicly-traded enterprise comprised of a portfolio of international assets with favorable access to the debt and equity capital markets, rather than, due to the limited availability of comparable companies and transactions, as a collection of discretely valued assets, and (ii) the market environment for international assets recovers. There can be no assurance that the Prisma Common Stock will subsequently be purchased or sold at prices comparable to the estimated values set forth above or that the value of Prisma Common Stock will increase. Refer to Section XIV., "Risk Factors and Other Factors to be Considered" for a discussion of numerous risk factors that could affect Prisma's financial results.

b. Methodology. A modified discounted cash flow analysis ("Modified DCF") was the primary method used to derive the reorganization value of Prisma based on the financial projections prepared by the Debtors' and Prisma's management. Prisma's management and Blackstone reviewed and evaluated data for possible use in connection with several alternative valuation techniques, including comparable company or transaction multiple methodologies. In addition, where there were prior marketing processes for certain of the Prisma Assets, the results of such processes were examined. These alternative valuation methodologies were ultimately deemed to be of limited applicability for purposes of valuing the Prisma Assets, as well as Prisma in its entirety, considering the limited availability of comparable companies and transactions in the subject industry and geographic markets.

The Modified DCF approach involves deriving the unlevered free cash flows that the Prisma Assets would generate assuming a set of financial projections are realized. Financial projections were prepared by Prisma management to reflect the most likely cash flows available to Prisma in respect of its interests in the Prisma companies, adjusted for the probability that certain material impacts to such cash flows occur. The cash flows for each of the Prisma Assets are discounted at the respective assets' estimated post-restructuring cost of capital to determine an aggregate, "pre-corporate" asset value for Prisma. The cost of capital is derived for each of Prisma's Assets based upon a Capital Asset Pricing Model, utilizing inputs appropriate to each asset's market, size, leverage and other factors. Prisma's projected unallocated corporate expenses are then discounted and deducted from the aggregate pre-corporate value of Prisma's Assets to arrive at a total enterprise and equity value for Prisma. All such discounted cash flows are discounted to December 31, 2003, while projected calendar year 2003 cash and cash flows inuring to the Prisma companies are also reflected in enterprise and equity value and are undiscounted for purposes of this analysis.

c. Variances and Risks. Refer to Section XIV.C., "Variance from Valuations, Estimates and Projections" for a discussion regarding the potential for variance from the projections and valuation described above and Section XIV., "Risk Factors and Other Factors to be Considered" in general for a discussion of the risks associated with Prisma.

ESTIMATES OF VALUE DO NOT PURPORT TO BE APPRAISALS NOR DO THEY NECESSARILY REFLECT THE VALUE THAT MAY BE REALIZED IF ASSETS ARE SOLD. ESTIMATES OF VALUE REPRESENT HYPOTHETICAL ENTERPRISE VALUES ASSUMING THE IMPLEMENTATION OF THE BUSINESS PLAN AS WELL AS OTHER SIGNIFICANT ASSUMPTIONS. SUCH ESTIMATES WERE DEVELOPED SOLELY FOR PURPOSES OF FORMULATING AND NEGOTIATING A CHAPTER 11 PLAN FOR THE DEBTORS AND ANALYZING THE PROJECTED RECOVERIES THEREUNDER. THE ESTIMATED EQUITY VALUE IS HIGHLY DEPENDENT UPON ACHIEVING THE FUTURE FINANCIAL RESULTS SET FORTH IN THE PROJECTIONS AS WELL AS THE REALIZATION OF CERTAIN OTHER ASSUMPTIONS, WHICH ARE NOT GUARANTEED.

THE VALUATIONS SET FORTH HEREIN REPRESENT ESTIMATED VALUES AND DO NOT NECESSARILY REFLECT VALUES THAT COULD BE ATTAINABLE IN PUBLIC OR PRIVATE MARKETS. THE EQUITY VALUE ASCRIBED IN THE ANALYSIS DOES NOT PURPORT TO BE AN ESTIMATE OF THE MARKET VALUE OF PRISMA STOCK DISTRIBUTED PURSUANT TO A CHAPTER 11 PLAN. SUCH VALUE, IF ANY, MAY BE MATERIALLY DIFFERENT FROM THE EQUITY VALUE RANGES ASSOCIATED WITH THE VALUATION ANALYSIS.

ADDITIONALLY, THE VALUES SET FORTH HEREIN ASSUME CERTAIN LEVELS OF TARIFFS OR RATES OF RETURN FOR THE CONSTITUENT ASSETS. SUCH RATES ARE HIGHLY REGULATED, SUBJECT TO PERIODIC CHANGES, AND IN CERTAIN CIRCUMSTANCES ARE THE OUTCOME OF POLITICAL PROCESSES IN THE SUBJECT JURISDICTIONS. THERE IS NO GUARANTEE THAT THE CURRENT RATE LEVELS WILL NOT CHANGE MATERIALLY IN THE FUTURE OR WILL PROVIDE ADEQUATE REIMBURSEMENT FOR THE SERVICES PROVIDED BY PRISMA. ANY SUCH CHANGES ARE ENTIRELY BEYOND PRISMA'S CONTROL AND MAY HAVE A MATERIAL ADVERSE IMPACT ON ACTUAL RESULTS. FURTHER, AS PRISMA OPERATES PRIMARILY IN FOREIGN JURISDICTIONS, SUCH POLITICAL PROCESSES OFTEN LEAD TO GREATER VOLATILITY IN REGULATORY OUTCOMES THAN MIGHT OCCUR IN THE UNITED STATES. ADDITIONALLY, OPERATIONS IN THE

EMERGING MARKETS ARE GENERALLY SUBJECT TO GREATER RISK OF GLOBAL ECONOMIC SLOWDOWN, POLITICAL UNCERTAINTY, CURRENCY DEVALUATION, EXCHANGE CONTROLS AND THE ABILITY TO ENFORCE AND DEFEND LEGAL AND CONTRACTUAL RIGHTS THAN ARE DOMESTIC COMPANIES. SUCH RISK FACTORS MAY ALSO HAVE A MATERIAL ADVERSE IMPACT ON PRISMA'S ACTUAL RESULTS.

PRISMA OPERATES IN HEAVILY REGULATED INDUSTRIES IN DIVERSE COUNTRIES, INCLUDING EMERGING MARKETS. CHANGES TO THE CURRENT REGULATORY OR POLITICAL ENVIRONMENT IN THESE COUNTRIES MAY HAVE A MATERIAL ADVERSE IMPACT ON PRISMA'S ACTUAL RESULTS. FOR FURTHER DISCUSSION ON THESE AND OTHER RISKS ATTENDANT WITH PRISMA, REFER TO THE ENTIRETY OF SECTION X., "PRISMA ENERGY INTERNATIONAL INC." AND SECTION XIV., "RISK FACTORS AND OTHER FACTORS TO BE CONSIDERED".

C. Legal Proceedings

Certain of the businesses to be transferred to Prisma are currently involved either as plaintiffs or defendants in pending arbitrations or civil litigation. Those arbitrations or civil litigations that may be material to the businesses are identified below. In addition to these arbitrations or civil litigations, certain of the businesses are involved in regulatory or administrative proceedings. Refer to Section X.A., "Business" for further information about regulatory or administrative proceedings that may be material.

1. Accroven

a. Tecnoconsult Constructor Barcelona S.A. (Tecnoconsult) v. Accroven (No. 27436, Caracas 10th Commercial & Civil Court of the Judicial Circuit of the Metropolitan Area). In May 2002, Tecnoconsult, a subcontractor to Consorcio Tecron, sued Accroven on its own behalf and as an assignee of another subcontractor Moinfra S.A. for approximately $1.8 million in alleged unpaid costs and fees for the construction of the Accroven facilities. Accroven maintains that it is not liable for the claims because it was never in privity with Tecnoconsult or Moinfra. Tecnoconsult obtained an order to attach Accroven assets, however, Accroven posted a bond to preclude such attachment and such bond was accepted by the court. No date has been set for Accroven to answer the substantive allegations of the complaint. Settlement discussions are ongoing.

b. Tecnoconsult Constructor Barcelona S.A. (Tecnoconsult) v. Accroven (Caracas 11th Commercial & Civil Court of the Judicial Circuit of the Metropolitan Area). Consorcio Tecron and nine other subcontractors have also alleged that Accroven owes them unpaid costs and fees for the construction of the Accroven facilities. In June 2003, Accroven settled with the nine subcontractors for approximately $2.1 million. In July 2003, Tecnoconsult filed suit against Accroven, asserting that Consorcio Tecron assigned to it claims for approximately $2 million. Accroven has not yet been served with the suit, but expects to assert similar defenses in this action. Settlement discussions are ongoing.

2. Transredes

a. CNA Insurance Company (Europe) Ltd. and LaBoliviana Cuacruz de Seguros y Reasseguros, et al. v. Transredes (London Commercial Court). Transredes's OSSA II pipeline suffered a perforation in January 2000, which caused an estimated 29,000 barrels of oil to be spilled into the Desaguadero River near the village of Calacoto. Transredes presented a claim for approximately $50 million in clean-up and third-party liability costs that it incurred, paid, and recorded in its financials to its insurer, LaBoliviana. In March 2000, CNA, a reinsurer to LaBoliviana, filed an action in London Commercial Court to avoid the reinsurance policy. CNA and other reinsurers have since also alleged that the loss is not covered. LaBoliviana has adopted that allegation. Brokers have been joined to the action. The parties participated in a court-ordered mediation on October 23, 2003.

b. Carolina Ortiz Paz v. Transredes S.A. (Santa Cruz 6th Civil Court, Bolivia). In December 2002, Carolina Ortiz Paz filed a civil action for $10 million in damages against Transredes claiming diminution of property value and lost opportunity to develop her real estate project because the ONSZ-2 Transredes line crosses her property. Transredes is vigorously defending the suit and has sought to join state-owned YPFB to the action, which Transredes argues is liable for any failure to obtain and present titles of easement to the disputed property. On October 14, 2003, Transredes was notified of the lower court's determination that Transredes was liable for unspecified damages to the plaintiff. Transredes has appealed this decision as well as the lower court's denial of Transredes's motion to join YPFB. Since the ruling, the lower court judge has been suspended indefinitely due to criminal allegations unrelated to this case.

3. Centragas

a. Centragas v. Ecogas and Ecopetrol (ICC Arbitration, Paris, France). In July 2001, Centragas initiated an ICC arbitration against Ecogas and Ecopetrol, Colombian government state enterprises. Centragas seeks to recover compensation from Ecogas and/or Ecopetrol in an unspecified amount for costs incurred as a result of a change in Colombian tax laws, which increased Centragas's tax liability. Centragas also seeks to clarify disputes over the quality of the gas transported through Centragas's pipeline and to receive payment for the construction of a facility to filter the gas transported through the pipeline. In May 2003, the Arbitral Tribunal issued an interim award holding that it has jurisdiction over the disputes. Centragas subsequently asked the Tribunal to take jurisdiction over a smaller dispute relating to changes in the tax law that arose in 2003. At present, briefing is expected to close in March 2004.

4. Elektro

a. Elektro v. Federal Tax Authority (13th Federal Court São Paulo) (PIS). On August 3, 1999, Elektro filed an action seeking to enjoin the Brazilian Federal Tax Authority from increasing the tax basis for Elektro's social integration taxes (PIS). The lower court granted a preliminary, and then a permanent, injunction to Elektro. An appeal is pending. If Elektro does not prevail, it will be required to pay additional social integration taxes of over approximately $5 million (as of October 1, 2003).

b. Elektro v. Federal Tax Authority (23rd Federal Court São Paulo) (COFINS). On August 3, 1999, Elektro filed an action seeking to enjoin the Brazilian Federal Tax Authority from increasing the tax basis for Elektro's social security contribution (COFINS). The lower court granted a preliminary, and then a permanent, injunction to Elektro. An appeal is pending. If Elektro does not prevail, it will be required to pay additional social security contribution taxes of approximately $19 million (as of October 1, 2003).

c. Elektro v. National Electricity Regulator (ANEEL) (XXI Federal Court, Brasília Circuit). In order to force ANEEL to implement a mechanism to track the quotas collected under the Energy Development Act and to include such quotas in its pass-through tariffs (as contemplated by the Act), Elektro filed an action seeking to enjoin ANEEL from collecting approximately $2.7 million (as of June 30, 2003) in quotas. ANEEL subsequently instituted a mechanism to track the quotas and to include them in its pass-through tariffs. The case has therefore been closed and Elektro has paid the quotas.

d. Elektro v. São Paulo Tax Authority (5th State Court São Paulo). Elektro filed a lawsuit in state court to obtain a legal determination of the proper methodology for the calculation of ICMS (a Value Added Tax), which is levied at the state level. On September 1, 2003, the appeals court (the 10th Court of the Public Treasury) granted an injunction prohibiting the Brazilian fiscal authorities from levying any fines or penalties against Elektro for its calculation of the ICMS tax or from making any corrections to such calculation until the merits of the case have been decided.

There can be no assurance that the case will ultimately be decided in Elektro's favor. Since privatization, Elektro has calculated ICMS based on measured capacity of electric energy. This was the calculation utilized by CESP, Elektro's state-owned predecessor, and is based on legal grounds established by several pre- and post-privatization opinions, as well as legal precedent. Other LDCs calculate the ICMS tax based on contracted demand, independent of actual energy consumption, which results in a greater tax burden to the end-user and a larger tax base for the state. This situation was identified in an on-going informal monitoring process by the state authorities that was initiated in early 2002, but no formal notification from the authorities has been received. Total exposure to Elektro in the event of an unfavorable finding is approximately $6 million (as of October 1, 2003), which includes interest, but assumes no penalties.

e. Criminal Investigations. The Brazilian Penal Code requires a criminal investigation upon an occurrence alleged to cause physical damage, death, or environmental damage in the concession area. Once completed, the investigating body submits a report to the Criminal Court for review by a Public Attorney who may (i) request a criminal proceeding; (ii) request further investigation; or (iii) recommend that the matter be closed. There are currently 40 such investigations underway relating to accidents that occurred in the Elektro concession area, environmental damage, and other claims. Additionally, one investigation is pending regarding a controversy in calculation of payment of ICMS, a state tax collected by the LDCs from their consumers. In the four years since the concession was granted, no investigation has resulted in a formal criminal charge or prosecution.

5. Cuiabá

a. Empresa Produtora de Energia Ltda. (EPE) v. AGF Brazil Seguros S.A. (AGF) (São Paulo Civil Court). In August 2002, EPE filed suit against AGF, a Brazilian insurance company, to recover approximately $30 million in insurance proceeds for business interruption and material damages resulting from a turbine failure at its power plant in Cuiabá. AGF has denied coverage on various grounds, including that EPE knew of, prior to the policy inception, material defects in the blades that led to the failure. EPE denies this contention and intends to vigorously pursue its rights against AGF.

b. Gasocidente do Mato Grosso Ltda. (GasMat) v. AGF Brazil Seguros S.A. (AGF) (São Paulo Civil Court). In August 2002, GasMat filed suit against AGF to recover approximately $4 million in insurance proceeds for contingent business interruption resulting from the turbine failure at the EPE power plant in Cuiabá. AGF has denied coverage. An initial hearing was held in the case on November 5, 2003. GasMat intends to vigorously pursue its rights against AGF.

c. Gas Oriente Boliviano Ltda. (GasBol), Southern Cone Gas Ltd. (SCG), and Transborder Gas Services Ltd. (TBS) v. La Boliviana Ciacruzde Seguros Y Reaseguros, International Oil Insurers (IOI) and Following Reinsurers (London Court of International Arbitration). In August 2003, GasBol, SCG, and TBS filed a demand for arbitration against La Boliviana, IOI (lead reinsurer), and following reinsurers to recover approximately $13 million in insurance proceeds for contingent business interruption resulting from the turbine failure at the EPE power plant in Cuiabá. The insurers have denied coverage. GasBol, SCG, and TBS intend to vigorously pursue their rights.

6. BLM

a. As a result of the enactment by the Ente Regulador Servicios Públicos of Panama of Resolution JD-1700, which effectively reduced the volume of energy that distribution companies were obligated to purchase under BLM's existing PPAs, BLM experienced a decrease in revenues. As a result, BLM has initiated several arbitral and judicial proceedings in Panama against Ente Regulador, the Government of Panama, and one of BLM's power purchasers, in an effort to obtain restitution of lost revenues totaling in excess of $8.5 million. These cases are still pending.

b. In other proceedings, BLM has filed claims challenging the Ente Regulador's implementation of Resolutions JD-3797 and JD-3920, which require BLM to reissue invoices under its PPAs utilizing a new pricing parity index for fuel established by the Panama Ministry of Commerce & Industry. This action by Ente Regulador had the effect of adjusting downward the fuel component of the price of energy under BLM's PPAs for a five-month period. The amount currently in dispute is approximately $1.7 million.

c. Bahia Las Minas Corp., Aseguradora Mundial, S.A. v. Cox Insurance Holdings, PLC, et al. (No. 6-02-453, U.S. District Court, Southern District of Texas, Houston Division). BLM filed suit in 2002 in the U.S. District Court for the Southern District of Texas in Galveston against a consortium of reinsurers led by Cox Insurance Holdings to recover in excess of $5 million in extra-contractual damages, insurance proceeds for property damage and interruption of service, prejudgment interest, and attorneys' fees resulting from a lightning strike. The suit was transferred to Houston. After mediation on August 7, 2003, BLM settled with AIG, though not with any of the other carriers. The remaining insurers have filed a motion to dismiss for lack of subject matter jurisdiction in the federal court action, and have filed a declaratory judgment action in state court seeking a ruling that coverage does not exist under BLM's policy. The state court action has been assigned to the Honorable Judge Levi Benton in the District Court for Harris County, Texas.

7. ENS

a. Polskie Gornictwo Naftowe i Gazownictwo, S. A. (PGNiG) v. Elektrocieplownia Nowa Sarzyna Sp. z o. o. (ENS) (No. VI Gco 56/03, Circuit Court, 6th Commercial Division, Rzeszow, Poland). In March 2003, PGNiG filed an application for injunction against ENS to secure approximately $9 million in claims under the long-term gas supply contracts between the parties. The underlying disputes began in mid-2000 when the Polish government instituted a new regulatory scheme for gas prices. ENS contended that the prices PGNiG could charge it for gas supplies could not exceed the prices found in PGNiG's approved tariff. PGNiG, on the other hand, claimed it was entitled to charge ENS the higher prices under the gas supply agreements. The parties signed a settlement agreement on August 1, 2003. Pursuant to the settlement, PGNiG waived its claims against ENS and filed a petition with the court to discontinue the injunction proceedings. The court has approved the petition and the case has been dismissed. As part of the settlement, the parties agreed that from January 1, 2003 going forward ENS will pay for gas according to PGNiG's approved tariff.

8. SECLP

SECLP is a defendant in several legal proceedings in the Dominican Republic, including:

a. Five lawsuits brought between 2000-2003 by approximately 200 residents and businesses against SECLP and Smith Cogeneration International, Inc., alleging that the operation of the Puerto Plata power plant damaged property values in their community of Costambar. Damages are unspecified and no trial date has been set. A hearing regarding consolidation of the five suits was held on October 21, 2003; however, the hearing was continued until November 20, 2003 because the plaintiffs did not properly summon World Bank and International Finance Corporation before the court. In addition to hearing the motion regarding consolidation, the court is also likely to hear various discovery motions and procedural motions at the November 20, 2003 hearing.

b. An arbitration proceeding brought by an operator of a hotel alleging SECLP breached a settlement agreement arising from a nuisance dispute related to operation of the Puerto Plata power plant. The plaintiff obtained an award of DOP187,000,000 (approximately $6 million) plus interest. SECLP has appealed the award on several grounds, including that the arbitration panel did not proceed properly.

c. A lawsuit filed in 2001 against CDC, CDCB, SECLP and five other defendants in which the plaintiff seeks to recover approximately DOP500,000,000 (approximately $15.6 million) from CDC that it claims CDC wrongfully dispersed to SECLP and the other defendants. SECLP is not a party to the agreement between CDC and the plaintiff that is the subject of the lawsuit, and has filed a motion to be dismissed from the case.

d. Several lawsuits filed by Montecristi Corp. in 1998 against SECLP, Smith Cogeneration Management, and Smith Cogeneration International, and Don Smith claiming breach of an alleged joint venture agreement related to the plaintiff's participation in the Puerto Plata power plant project. At the time the suits were filed, plaintiff sought approximately $15 million in damages, the enforcement of the alleged joint venture agreement and the appointment of a judicial administrator to operate the power plant until the matter was resolved. Based on a prior settlement and release, a court in New York enjoined the plaintiff from prosecuting the action against the defendants in the Dominican Republic. To date, the Dominican courts have declined to recognize the injunction or to halt the cases pending in the Dominican Republic, and SECLP has appealed to the Dominican Supreme Court.

D. Directors

On the Effective Date, Prisma's board of directors will consist of individuals designated by the Debtors, after consultation with the Creditors' Committee, all of which shall be disclosed prior to the Confirmation Hearing. In the event that, during the period from the Confirmation Date up to and including the Effective Date, circumstances require the substitution of one (1) or more persons selected to serve, the Debtors shall file a notice thereof with the Bankruptcy Court and, for purposes of section 1129 of the Bankruptcy Code, any such replacement person, designated after consultation with the Creditors' Committee, shall be deemed to have been selected or disclosed prior to the Confirmation Hearing. Thereafter, the terms and manner of selection of directors of Prisma shall be as provided in Prisma's organizational documents, as the same may be amended. Each director will serve until a successor is elected and qualified or until his or her earlier resignation or removal.

Set forth below is biographical information for five individuals who are expected to be members of Prisma's board of directors on the Effective Date. Each of these directors have held their position at Prisma since Prisma's formation or shortly thereafter. Currently there is an interim management team in place for Prisma.

1. Ron W. Haddock

Ron W. Haddock, 63, is executive chairman of Prisma and an employee of an affiliate of Prisma. He was president and CEO of FINA, Inc. from 1989 until 2000. He joined FINA in Dallas in 1986 as executive vice president and chief operating officer. Prior to joining FINA, Mr. Haddock was with Exxon for 23 years in various engineering and management positions, including vice president and director of Exxon's operations in the Far East, executive assistant to the chairman, vice president of refining, and general manager of corporate planning. Mr. Haddock currently also serves on the boards of ENE (post-bankruptcy), Elektro, Alon Energy USA, Southwest Securities, Adea Solutions, Safety Kleen and SepraDyne. Mr. Haddock has a degree in mechanical engineering from Purdue University. He is a resident of Dallas.

2. John W. Ballantine

John W. Ballantine, 57, has been a private investor since 1998, when he left First Chicago NBD Corporation/The First National Bank of Chicago as its Chief Risk Management Officer and Executive Vice President. During his career with First Chicago, Mr. Ballantine held senior positions including head of international banking, head of New York banking, and Chief Credit and Market Risk Officer. He currently also serves on the boards of ENE (post-bankruptcy), Scudder Funds, FNB Corporation, First Oak Brook Bancshares and the Oak Brook Bank and American Healthways. Mr. Ballantine has a bachelor's degree from Washington and Lee University and an MBA from the University of Michigan, Ann Arbor. He is a resident of Chicago.

3. Philippe A. Bodson

Philippe A. Bodson, 58, has experience as a chief executive officer for utility and industrial concerns with international activities, including Glaverbel from 1980-1989, Tractebel from 1989-1999 and Lernout & Hauspie (post-bankruptcy) in 2001. Mr. Bodson also has extensive board experience, including serving as a director for Glaverbel, Diamond Boart, Societé Generale, Fortis, and British Telecom Belgium. Mr. Bodson has a degree in civil engineering from the University of Leige in Belgium and a master's degree in business administration from INSEAD. He is a resident of Brussels, Belgium.

4. Lawrence S. Coben

Lawrence S. "Larry" Coben, 45, is the senior principal of Sunrise Capital Partners.[40] Mr. Coben previously served as chief executive officer of Bolivian Power Company, Ltd., managing director of Liberty Power Corp., Chairman of Recovery Corporation of America and senior vice president of Catalyst Energy Corporation. He is president of the board of directors of New York Stage and Film, a director of the Bolivian-American Chamber of Commerce and co-chairman of the Lieberman 2004 National Energy Policy Committee. Mr. Coben has a bachelor's degree in economics from Yale University and a juris doctorate degree from Harvard Law School Mr. Coben also has a master's degree and is completing a doctorate in anthropology from the University of Pennsylvania. He is a resident of New Hampshire.

5. Dr. Paul K. Freeman

Dr. Paul K. Freeman, 53, has been a consultant since 1998 to international financial institutions on designing strategies for developing countries to cope with natural disasters. During that same period, Dr. Freeman variously served as adjunct professor at the University of Denver, visiting research fellow at Oxford University, project leader at the International Institute for Applied Systems Analysis and lecturer at the University of Vienna. Dr. Freeman was chief executive of the ERIC Companies, an environmental risk management firm, from 1985-1998 and a practicing attorney specializing in international law from 1975-1985. He currently serves on the corporate advisory board of the Wharton School Risk and Decision Process Center at the University of Pennsylvania and the board of trustees of the Scudder Mutual Funds. Dr. Freeman has a bachelor's degree in economics from the University of Denver, juris

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[40] Sunrise Capital Partners is an affiliate of Houlihan Lokey Howard & Zukin, financial advisors to the Creditors' Committee.

doctorate degree from Harvard Law School, and a doctorate in economics from the University of Vienna. He is a resident of Denver.

E. Prisma Contribution and Separation Agreement

It is contemplated that the Prisma Enron Parties will contribute the Prisma Assets to Prisma at one or more closings in exchange for shares of Prisma common stock commensurate with the value of such Prisma Assets and in accordance with the Prisma Contribution and Separation Agreement.

1. Prisma Assets to be Contributed. ENE will have the sole discretion, subject to the consent of the Creditors' Committee or as otherwise provided in the Contribution and Separation Agreement (as applicable, for purposes of this section only, the "Requisite Consent"), to select the Prisma Assets to be contributed at any closing, to rescind Prisma Assets that have been contributed or to add to or subtract from the Prisma Assets available for contribution, including the addition or deletion of Prisma Enron Parties, if necessary, at any time until the Prisma Distribution Date or the Prisma Sale Date.

2. Change in Relative Value of any Prisma Assets. In the event of any change, circumstance or event that could be considered to have materially changed the estimated value of any of the Prisma Assets contemplated to be transferred to Prisma relative to the estimated value of all of the Prisma Assets that have been or are contemplated to be contributed to Prisma, ENE contemplates that it may in its reasonable discretion, subject to the Requisite Consent, reallocate the Prisma Shares to be issued in exchange for any of the Prisma Assets so impacted to reflect such change in estimated values.

3. Consents. Each of the Prisma Enron Parties and Prisma are expected to covenant to cooperate and to use commercially reasonable efforts to obtain certain consents, orders and permits deemed advisable to obtain prior to the consummation of any contribution, the Prisma Distribution Date or the Prisma Sale Date; provided that Enron shall have sole discretion, subject to the Requisite Consent, to contribute Prisma Assets or to consummate the Prisma Distribution or the Prisma Sale in the absence of any such consents, orders and permits. Refer to Section X.A.2., "Risk Factors" and Section XIV.I.5.a., "Contractual and Regulatory Disputes" for additional information.

4. Actions with Respect to the Prisma Distribution. ENE contemplates the eventual distribution to creditors of the capital stock of the Prisma Distributing Company, and the following actions to be taken by Prisma and the Prisma Enron Parties to effectuate such Prisma Distribution:

a. each Prisma Enron Party and Prisma, subject to the Requisite Consent, will take necessary actions to conform the organizational documents and capital structure of the Prisma Distributing Company as necessary to effectuate the Prisma Distribution;

b. to the extent provided in the Plan, on the Prisma Distribution Date, the shares of Prisma common stock held by the Prisma Enron Parties will be cancelled or assigned to the Prisma Distributing Company, if applicable;

c. Prisma will and, if applicable, the Prisma Enron Parties will cause the Prisma Distributing Company to issue the number of shares of its capital stock required by the Plan and take all actions necessary to ensure that those shares are duly authorized, validly issued, fully paid and nonassessable and free of any preemptive rights; and

d. as soon as practicable, Prisma will and, if applicable, the Prisma Enron Parties will cause the Prisma Distributing Company to, prepare, file and use reasonable best efforts to have declared effective by the SEC a registration statement on Form 10, take such other actions as may be necessary to register the Prisma Common Stock (or any applicable Prisma Distributing Company stock) under Section 12(b) or 12(g) of the Securities Exchange Act, and prepare, file, and use reasonable best efforts to have approved, an application for listing such capital stock to be distributed pursuant to the Plan on a national securities exchange or quoted in one of the NASDAQ markets, subject to official notice of distribution, in each case, as may be more fully described in the Plan.

5. Indemnification.

a. General Indemnification. The Prisma Contribution and Separation Agreement may contain certain limited indemnity obligations. Prisma and ENE may indemnify the Enron Indemnified Parties and the Prisma Indemnified Parties, respectively, against any liabilities resulting from third party claims caused by a material breach by such party of the Prisma Contribution and Separation Agreement occurring after the initial contribution. If such indemnification is provided, it is expected that each party's obligation to indemnify pursuant to the general indemnification will terminate upon the Prisma Distribution Date or the Prisma Sale Date, as the case may be, except for the obligation to indemnify against liabilities arising out of a material breach of a covenant in the Prisma Contribution and Separation Agreement that by its terms contemplates performance after such date, which shall survive for thirty (30) days following the expiration of the applicable period of time set forth therein. The Prisma Contribution and Separation Agreement may also provide for certain tax and employee benefits indemnification.

b. If provided, the obligation of ENE and its affiliates, on the one hand, and Prisma, on the other hand, to indemnify the Prisma Indemnified Parties and the Enron Indemnified Parties, respectively, is expected to be capped at a fixed aggregate dollar amount.

6. Termination. It is expected that ENE will have the right, in its discretion, subject to the Requisite Consent, to terminate the Prisma Contribution and Separation Agreement at any time prior to the initial contribution.

7. Certain Governance Provisions. From the date of the Prisma Contribution and Separation Agreement until the Prisma Distribution Date or the Prisma Sale Date, it is contemplated that Prisma shall be prohibited from taking certain specified actions without the approval of ENE, which may include:

a. disposing of any capital stock held directly or indirectly by Prisma in any subsidiary of Prisma or any other company that constitutes a Prisma Asset or selling any significant portion of the assets of Prisma or such companies;

b. entering into any new lines of business or changing the fiscal year;

c. establishing or modifying significant accounting methods, practices or policies or significant tax policies;

d. registering securities of Prisma, any subsidiary of Prisma or any other company that constitutes a Prisma Asset for issuance under U.S. federal or state securities laws or the laws of any foreign jurisdiction;

e. issuing any capital stock of Prisma, any subsidiary of Prisma or any other company that constitutes a Prisma Asset, or any securities convertible into, or exercisable or exchangeable for, capital stock of Prisma or such companies;

f. creating or assuming any indebtedness for borrowed money, in excess of certain limitations, for Prisma, any subsidiary of Prisma and any other company that constitutes a Prisma Asset, except for renewals, roll-overs or refinancings of existing indebtedness;

g. adopting or materially amending any equity-based bonus or employee benefit plan or program;

h. incurring (x) any non-maintenance capital expenditures, or commitments to make non-maintenance capital expenditures, in excess of certain limitations, or (y) annual maintenance capital expenditures, or commitments to make annual maintenance capital expenditures, in excess of certain limitations, in each case, by Prisma, the subsidiaries of Prisma and any other company that constitutes a Prisma Asset;

i. compromising or settling any litigation or proceeding in excess of a specified amount;

j. entering into any joint venture, partnership, merger or other business combination transaction;

k. amending in any manner the organizational or governing documents of Prisma, any subsidiary of Prisma or any other company that constitutes a Prisma Asset; or

l. commencing or joining in any voluntary or involuntary bankruptcy or insolvency filing against Prisma, any subsidiary of Prisma or any other company that constitutes a Prisma Asset.

8. Other Covenants. It is expected that the Prisma Contribution and Separation Agreement will also contain additional covenants, including covenants regulating the conduct of business pending any closing of the contemplated transactions, the preservation of records, the treatment of confidential information, information reporting obligations, the resolution of certain intercompany account and guarantee issues and the ownership, investigation and disposal of any casualty insurance claims of any Prisma Assets.

It is contemplated that upon any written request of ENE (made with the Requisite Consent) to Prisma at any time prior to the Prisma Distribution Date or Prisma Sale Date, the board of directors of Prisma will commence an auction process for the sale of, or other recapitalization or financing transaction with respect to, certain of its businesses or assets, subject to ENE approval of, and the Requisite Consent to, the terms and conditions of any such transaction.

9. Conditions to Closings. In addition to customary conditions to the obligations of the parties, including the representations and warranties being true and correct in all material respects, the absence of any serious legal impediment to any closing, absence of material breaches of the Prisma Contribution and Separation Agreement, performance of all covenants and agreements and the delivery of all closing documentation, it is expected that the obligation of the parties under the Prisma Contribution and Separation Agreement upon any closing of a contribution of Prisma Assets will be further conditioned upon (i) the release of all liens imposed on the Prisma Assets in connection with the Second Amended DIP Credit Agreement, (ii) the Bankruptcy Court's approval of the Prisma Contribution and Separation Agreement (and ancillary agreements, if any) and (iii) the Prisma Distribution or the Prisma Sale not having occurred.

F. Equity Compensation Plan

Following confirmation of the Plan, in order to attract, retain and motivate highly competent persons as key employees and/or directors of Prisma, Prisma expects to adopt a long-term equity incentive compensation plan providing for awards to such individuals. It is anticipated that the Compensation Committee of Prisma's Board of Directors will determine the specific terms of any grants made under such plan and will provide grants of awards designed to focus equity compensation on performance and alignment with shareholders interests; provided, however, that shares reserved for the plan will not exceed 10% of the Prisma Common Stock to be issued pursuant to the Plan, with projected annual share usage under the plan not exceeding 2%.

XI. The Litigation Trust and Special Litigation Trust

Capitalized terms used throughout this Disclosure Statement are defined in Appendix A: "Material Defined Terms for Enron Disclosure Statement" attached hereto.

A. The Litigation Trust

1. Establishment of the Trust

On the Effective Date, the Debtors, on their own behalf and on behalf of holders of Allowed Claims in Classes 3 through 180 shall execute the Litigation Trust Agreement and shall take all other steps necessary to establish the Litigation Trust. On the Effective Date, and in accordance with and pursuant to the terms of Section 22.4 of the Plan, the Debtors shall transfer to the Litigation Trust all of their right, title, and interest in the Litigation Trust Claims. In connection with the above-described rights and causes of action, any attorney-client privilege, work-product privilege, or other privilege or immunity attaching to any documents or communications (whether written or oral) shall be transferred to the Litigation Trust and shall vest in the Litigation Trustee and its representatives, and the Debtors, the Debtors in Possession and the Litigation Trustee are authorized to take all necessary actions to effectuate the transfer of such privileges.

2. Purpose of the Litigation Trust

The Litigation Trust shall be established for the sole purpose of liquidating its assets, in accordance with Treasury Regulation Section 301.7701-4(d), with no objective to continue or engage in the conduct of a trade or business.

3. Funding Expenses of the Litigation Trust

In accordance with the Litigation Trust Agreement and any agreements entered into in connection therewith, on the Effective Date, the Debtors shall transfer such amounts of Cash as jointly determined by the Debtors and the Creditors' Committee as necessary to fund the operations of the Litigation Trust. The Debtors and the Reorganized Debtors shall have no further obligation to provide any funding with respect to the Litigation Trust.

4. Transfer of Assets

a. The transfer of the Litigation Trust Claims to the Litigation Trust shall be made, as provided in the Plan, for the ratable benefit of the holders of Allowed Claims in Classes 3 through 180, only to the extent such holders in such Classes are entitled to distributions under the Plan. In partial satisfaction of Allowed Claims in Classes 3 through 180, the Litigation Trust Claims shall be transferred to such holders of Allowed Claims, to be held by the Debtors on their behalf. Immediately thereafter, on behalf of the holders of Allowed Claims in Classes 3 through 180, the Debtors shall transfer such Litigation Trust Claims to the Litigation Trust in exchange for Litigation Trust Interests for the ratable benefit of holders of Allowed Claims in Classes 3 through 180, in accordance with the Plan. Upon the transfer of the Litigation Trust Claims, the Debtors shall have no interest in or with respect to the Litigation Trust Claims or the Litigation Trust.

b. For all federal income tax purposes, all parties (including, without limitation, the Debtors, the Litigation Trustee and the beneficiaries of the Litigation Trust) shall treat the transfer of assets to the Litigation Trust in accordance with the terms of the Plan, as a transfer to the holders of Allowed Claims in Classes 3 through 180, followed by a transfer by such holders to the Litigation Trust and the beneficiaries of the Litigation Trust shall be treated as the grantors and owners thereof.

5. Valuation of Assets

As soon as possible after the Effective Date, but in no event later than thirty (30) days thereafter, the Litigation Trust Board shall inform, in writing, the Litigation Trustee of the value of the assets transferred to the Litigation Trust, based on the good faith determination of the Litigation Trust Board, and the Litigation Trustee shall apprise, in writing, the beneficiaries of the Litigation Trust of such valuation. The valuation shall be used consistently by all parties (including the Debtors, the Reorganized Debtors, the Litigation Trustee and the beneficiaries of the Litigation Trust) for all federal income tax purposes.

6. Litigation; Responsibilities of Litigation Trustee

a. The Litigation Trustee, upon direction by the Litigation Trust Board and the exercise of their collective reasonable business judgment, shall, in an expeditious but orderly manner, liquidate and convert to Cash the assets of the Litigation Trust, make timely distributions and not unduly prolong the duration of the Litigation Trust. The liquidation of the Litigation Trust Claims may be accomplished either through the prosecution, compromise and settlement, abandonment or dismissal of any or all claims, rights or causes of action, or otherwise. The Litigation Trustee, upon direction by the Litigation Trust Board, shall have the absolute right to pursue or not to pursue any and all Litigation Trust Claims as it determines is in the best interests of the beneficiaries of the Litigation Trust, and consistent with the purposes of the Litigation Trust, and shall have no liability for the outcome of its decision except for any damages caused by willful misconduct or gross negligence. The Litigation Trustee may incur any reasonable and necessary expenses in liquidating and converting the assets to Cash and shall be reimbursed in accordance with the provisions of the Litigation Trust Agreement.

b. The Litigation Trustee shall be named in the Confirmation Order or in the Litigation Trust Agreement and shall have the power (i) to prosecute for the benefit of the Litigation Trust all claims, rights and causes of action transferred to the Litigation Trust (whether such suits are brought in the name of the Litigation Trust or otherwise), and (ii) to otherwise perform the functions and take the actions provided for or permitted in the Plan or in any other agreement executed by the Litigation Trustee pursuant to the Plan. Any and all proceeds generated from such claims, rights, and causes of action shall be the property of the Litigation Trust.

7. Investment Powers

The right and power of the Litigation Trustee to invest assets transferred to the Litigation Trust, the proceeds thereof, or any income earned by the Litigation Trust, shall be limited to the right and power to invest such assets (pending periodic distributions in accordance with Section 22.8 of the Plan) in Cash Equivalents; provided, however, that (a) the scope of any such permissible investments shall be limited to include only those investments, or shall be expanded to include any additional investments, as the case may be, that a liquidating trust, within the meaning of Treasury Regulation Section 301.7701-4(d) may be permitted to hold, pursuant to the Treasury Regulations, or any modification in the IRS guidelines, whether set forth in IRS rulings, other IRS pronouncements or otherwise, and (b) the Litigation Trustee may expend the assets of the Litigation Trust (i) as reasonably necessary to meet contingent liabilities and to maintain the value of the assets of the Litigation Trust during liquidation, (ii) to pay reasonable administrative expenses (including, but not limited to, any taxes imposed on the Litigation Trust or fees and expenses in connection with litigation), and (iii) to satisfy other liabilities incurred or assumed by the Litigation Trust (or to which the assets are otherwise subject) in accordance with the Plan or the Litigation Trust Agreement; and, provided, further, that, under no circumstances, shall the Litigation Trust segregate the assets of the Litigation Trust on the basis of classification of the holders of Litigation Trust Interests, other than with respect to distributions to be made on account of Disputed Claims and Disputed Equity Interests in accordance with the provisions of the Plan.

8. Annual Distribution; Withholding

The Litigation Trustee shall distribute at least annually to the holders of Litigation Trust Interests all net cash income plus all net cash proceeds from the liquidation of assets (including as Cash for this purpose, all Cash Equivalents); provided, however, that the Litigation Trust may retain such amounts (i) as are reasonably necessary to meet contingent liabilities and to maintain the value of the assets of the Litigation Trust during liquidation, (ii) to pay reasonable administrative expenses (including any taxes imposed on the Litigation Trust or in respect of the assets of the Litigation Trust), and (iii) to satisfy other liabilities incurred or assumed by the Litigation Trust (or to which the assets are otherwise subject) in accordance with the Plan or the Litigation Trust Agreement. All such distributions shall be pro rata based on the number of Litigation Trust Interests held by a holder compared with the aggregate number of Litigation Trust Interests outstanding, subject to the terms of the Plan and the Litigation Trust Agreement. The Litigation Trustee may withhold from amounts distributable to any Person any and all amounts, determined in the Litigation Trustee's reasonable sole discretion, to be required by any law, regulation, rule, ruling, directive or other governmental requirement.

9. Reporting Duties

a. Federal Income Tax. Subject to definitive guidance from the IRS or a court of competent jurisdiction to the contrary (including the receipt by the Litigation Trustee of a private letter ruling if the Litigation Trustee so requests one, or the receipt of an adverse determination by the IRS upon audit if not contested by the Litigation Trustee), the Litigation Trustee shall file returns for the Litigation Trust as a grantor trust pursuant to Treasury Regulation Section 1.671-4(a). The Litigation Trustee shall also annually send to each holder of a Litigation Trust Interest a separate statement setting forth the holder's share of items of income, gain, loss, deduction or credit and will instruct all such holders to report such items on their federal income tax returns.

b. Allocations of Litigation Trust Taxable Income. Allocations of Litigation Trust taxable income shall be determined by reference to the manner in which an amount of cash equal to such taxable income would be distributed (without regard to any restrictions on distributions described in the Plan) if, immediately prior to such deemed distribution, the Litigation Trust had distributed all of its other assets (valued for this purpose at their tax book value) to the holders of the Litigation Trust Interests, taking into account all prior and concurrent distributions from the Litigation Trust (including all distributions held in escrow pending the resolution of Disputed Claims). Similarly, taxable loss of the Litigation Trust will be allocated by reference to the manner in which an economic loss would be borne immediately after a liquidating distribution of the remaining Litigation Trust Claims. The tax book value of the Litigation Trust Claims for this purpose shall equal their fair market value on the Effective Date or, if later, the date such assets were acquired by the Litigation Trust, adjusted in either case in accordance with tax accounting principles prescribed by the IRC, the regulations and other applicable administrative and judicial authorities and pronouncements.

c. Other. The Litigation Trustee shall file (or cause to be filed) any other statements, returns or disclosures relating to the Litigation Trust that are required by any governmental unit.

10. Trust Implementation

On the Effective Date, the Litigation Trust shall be established and become effective for the benefit of Allowed Claims in Classes 3 through 178. The Litigation Trust Agreement shall be filed in the Plan Supplement and shall contain provisions customary to trust agreements utilized in comparable circumstances, including, but not limited to, any and all provisions necessary to ensure the continued treatment of the Litigation Trust as a grantor trust for federal income tax purposes. All parties (including the Debtors, the Litigation Trustee and holders of Allowed Claims in Classes 3 through 180) shall execute any documents or other instruments as necessary to cause title to the applicable assets to be transferred to the Litigation Trust.

11. Registry of Beneficial Interests

The Litigation Trustee shall maintain a registry of the holders of Litigation Trust Interests.

12. Termination

The Litigation Trust shall terminate no later than the fifth (5th) anniversary of the Effective Date; provided, however, that, on or prior to the date three (3) months prior to such termination, the Bankruptcy Court, upon motion by a party in interest, may extend the term of the Litigation Trust if it is necessary to the liquidation of the Litigation Trust Claims. Notwithstanding the foregoing, multiple extensions can be obtained so long as Bankruptcy Court approval is obtained at least three (3) months prior to the expiration of each extended term.

13. Net Litigation Trust Recovery/Assignment of Claims

a. Net Judgment. Notwithstanding anything contained in the Plan to the contrary, in the event that a defendant in a litigation brought by the Litigation Trustee for and on behalf of the Litigation Trust (i) is required by a Final Order to make payment to the Litigation Trust (the "Judgment Amount"), and (ii) is permitted by a Final Order to assert a right of setoff under section 553 of the Bankruptcy Code or applicable non-bankruptcy law against the Judgment Amount (a "Valid Setoff"), (y) such defendant shall be obligated to pay only the excess, if any, of the amount of the Judgment Amount over the Valid Setoff and (z) none of the Litigation Trust, the holders or beneficiaries of the Litigation Trust Interests shall be entitled to assert a claim against the Debtors or the Reorganized Debtors with respect to the Valid Setoff.

b. Assignment. Notwithstanding anything contained in the Plan to the contrary, in the event that a compromise and settlement of a Litigation Trust Claim or a Final Order with respect to a Litigation Trust Claim provides for a waiver, subordination or disallowance of a defendant's Claim or Claims against one or more of the Debtors, for purposes of computing amounts of distributions, (i) such claim shall be deemed allowed in the amount determined by the Bankruptcy Court by Final Order, (ii) such defendant shall be deemed to have assigned such Claim or Claims and right to receive distributions in accordance with the Plan to the Litigation Trust, (iii) the Disbursing Agent shall make distributions with respect to such Allowed Claims to the Litigation Trust and (iv) such defendant shall not be entitled to receive distributions from the Litigation Trust on account thereof.

c. **Multiple Recoveries**. In the event that any avoidance or recovery action commenced in accordance with sections 541, 544, 545, 547, 548, 549, 550, 551 and 553 of the Bankruptcy Code is compromised and settled in connection with a Litigation Trust Claim, the proceeds of any recovery, waiver, subordination or disallowance resulting from such compromise and settlement shall be allocated first to the Debtor or Debtors entitled to recovery in accordance with Section 28.1 of the Plan and then to the Litigation Trust.

B. The Special Litigation Trust

1. Establishment of the Trust

On the Effective Date, the Debtors, on their own behalf and on behalf of holders of Allowed Claims in Classes 3 through 180 shall execute the Special Litigation Trust Agreement and shall take all other steps necessary to establish the Special Litigation Trust. On the Effective Date, and in accordance with and pursuant to the terms of Section 23.4 of the Plan, the Debtors shall transfer to the Special Litigation Trust all of their right, title, and interest in the Special Litigation Trust Claims. In connection with the above-described rights and causes of action, any attorney-client privilege, work-product privilege, or other privilege or immunity attaching to any documents or communications (whether written or oral) transferred to the Special Litigation Trust shall vest in the Special Litigation Trustee and its representatives, and the Debtors and the Special Litigation Trustee are authorized to take all necessary actions to effectuate the transfer of such privileges.

2. Purpose of the Special Litigation Trust

The Special Litigation Trust shall be established for the sole purpose of liquidating its assets, in accordance with Treasury Regulation Section 301.7701-4(d), with no objective to continue or engage in the conduct of a trade or business.

3. Funding Expenses of the Special Litigation Trust

In accordance with the Special Litigation Trust Agreement and any agreements entered into in connection therewith, on the Effective Date, the Debtors shall transfer such amounts of Cash as jointly determined by the Debtors and the Creditors' Committee as necessary to fund the operations of the Special Litigation Trust. The Debtors and the Reorganized Debtors shall have no further obligation to provide any funding with respect to the Special Litigation Trust.

4. Transfer of Assets

a. The transfer of the Special Litigation Trust Claims to the Special Litigation Trust shall be made, as provided in the Plan, for the ratable benefit of the holders of Allowed Claims in Classes 3 through 180, only to the extent such holders in such Classes are entitled to distributions under the Plan. In partial satisfaction of Allowed Claims in Classes 3 through 180, the Special Litigation Trust Claims shall be transferred to such holders of Allowed Claims, to be held by the Debtors on their behalf. Immediately thereafter, on behalf of the holders of Allowed Claims in Classes 3 through 180, the Debtors shall transfer such Special Litigation Trust Claims to the Special Litigation Trust in exchange for Special Litigation Trust

Interests for the ratable benefit of holders of Allowed Claims in Classes 3 through 180, in accordance with the Plan. Upon the transfer of the Special Litigation Trust Claims, the Debtors shall have no interest in or with respect to the Special Litigation Trust Claims or the Special Litigation Trust.

b. For all federal income tax purposes, all parties (including, without limitation, the Debtors, the Special Litigation Trustee and the beneficiaries of the Special Litigation Trust) shall treat the transfer of assets to the Special Litigation Trust in accordance with the terms of the Plan, as a transfer to the holders of Allowed Claims in Classes 3 through 180, followed by a transfer by such holders to the Special Litigation Trust and the beneficiaries of the Special Litigation Trust shall be treated as the grantors and owners thereof.

5. Valuation of Assets

As soon as possible after the Effective Date, but in no event later than thirty (30) days thereafter, the Special Litigation Trust Board shall inform, in writing, the Special Litigation Trustee of the value of the assets transferred to the Special Litigation Trust, based on the good faith determination of the Special Litigation Trust Board, and the Special Litigation Trustee shall apprise, in writing, the beneficiaries of the Special Litigation Trust of such valuation. The valuation shall be used consistently by all parties (including the Debtors, the Reorganized Debtors, the Special Litigation Trustee and the beneficiaries of the Special Litigation Trust) for all federal income tax purposes.

6. Litigation of Assets; Responsibilities of Special Litigation Trustee

a. The Special Litigation Trustee, upon direction by the Special Litigation Trust Board and the exercise of their collective reasonable business judgment, shall, in an expeditious but orderly manner, liquidate and convert to Cash the assets of the Special Litigation Trust, make timely distributions and not unduly prolong the duration of the Special Litigation Trust. The liquidation of the Special Litigation Trust Claims may be accomplished either through the prosecution, compromise and settlement, abandonment or dismissal of any or all claims, rights or causes of action, or otherwise. The Special Litigation Trustee, upon direction by the Special Litigation Trust Board, shall have the absolute right to pursue or not to pursue any and all claims, rights, or causes of action, as it determines is in the best interests of the beneficiaries of the Special Litigation Trust, and consistent with the purposes of the Special Litigation Trust, and shall have no liability for the outcome of its decision except for any damages caused by willful misconduct or gross negligence. The Special Litigation Trustee may incur any reasonable and necessary expenses in liquidating and converting the assets to Cash.

b. The Special Litigation Trustee shall be named in the Confirmation Order or in the Special Litigation Trust Agreement and shall have the power (i) to prosecute for the benefit of the Special Litigation Trust all claims, rights and causes of action transferred to the Special Litigation Trust (whether such suits are brought in the name of the Special Litigation Trust or otherwise), and (ii) to otherwise perform the functions and take the actions provided for or permitted herein or in any other agreement executed by the Special Litigation Trustee pursuant to the Plan. Any and all proceeds generated from such claims, rights, and causes of action shall be the property of the Special Litigation Trust.

7. Investment Powers

The right and power of the Special Litigation Trustee to invest assets transferred to the Special Litigation Trust, the proceeds thereof, or any income earned by the Special Litigation Trust, shall be limited to the right and power to invest such assets (pending periodic distributions in accordance with Section 23.8 of the Plan) in Cash Equivalents; provided, however, that (a) the scope of any such permissible investments shall be limited to include only those investments, or shall be expanded to include any additional investments, as the case may be, that a liquidating trust, within the meaning of Treasury Regulation Section 301.7701-4(d) may be permitted to hold, pursuant to the Treasury Regulations, or any modification in the IRS guidelines, whether set forth in IRS rulings, other IRS pronouncements or otherwise, and (b) the Special Litigation Trustee may expend the assets of the Special Litigation Trust (i) as reasonably necessary to meet contingent liabilities and to maintain the value of the assets of the Special Litigation Trust during liquidation, (ii) to pay reasonable administrative expenses (including, but not limited to, any taxes imposed on the Special Litigation Trust or fees and expenses in connection with litigation), and (iii) to satisfy other liabilities incurred or assumed by the Special Litigation Trust (or to which the assets are otherwise subject) in accordance with the Plan or the Special Litigation Trust Agreement; and, provided, further, that, under no circumstances, shall the Special Litigation Trust segregate the assets of the Special Litigation Trust on the basis of classification of the holders of Special Litigation Trust Interests, other than with respect to distributions to be made on account of Disputed Claims and Disputed Equity Interests in accordance with the provisions of the Plan.

8. Annual Distribution; Withholding

The Special Litigation Trustee shall distribute at least annually to the holders of Special Litigation Trust Interests all net cash income plus all net cash proceeds from the liquidation of assets (including as Cash for this purpose, all Cash Equivalents); provided, however, that the Special Litigation Trust may retain such amounts (i) as are reasonably necessary to meet contingent liabilities and to maintain the value of the assets of the Special Litigation Trust during liquidation, (ii) to pay reasonable administrative expenses (including any taxes imposed on the Special Litigation Trust or in respect of the assets of the Special Litigation Trust), and (iii) to satisfy other liabilities incurred or assumed by the Special Litigation Trust (or to which the assets are otherwise subject) in accordance with the Plan or the Special Litigation Trust Agreement. All such distributions shall be pro rata based on the number of Special Litigation Trust Interests held by a holder compared with the aggregate number of Special Litigation Trust Interests outstanding, subject to the terms of the Plan and the Special Litigation Trust Agreement. The Special Litigation Trustee may withhold from amounts distributable to any Person any and all amounts, determined in the Special Litigation Trustee's reasonable sole discretion, to be required by any law, regulation, rule, ruling, directive or other governmental requirement.

9. Reporting Duties

a. Federal Income Tax. Subject to definitive guidance from the IRS or a court of competent jurisdiction to the contrary (including the receipt by the Special Litigation Trustee of a private letter ruling if the Special Litigation Trustee so requests one, or the receipt of an adverse determination by the IRS upon audit if not contested by the Special Litigation Trustee), the Special Litigation Trustee shall file returns for the Special Litigation Trust as a grantor trust pursuant to Treasury Regulation Section 1.671-4(a). The Special Litigation Trustee shall also annually send to each holder of a Special Litigation Trust Interest a separate statement setting forth the holder's share of items of income, gain, loss, deduction or credit and shall instruct all such holders to report such items on their federal income tax returns.

b. Allocations of Special Litigation Trust Taxable Income. Allocations of Special Litigation Trust taxable income shall be determined by reference to the manner in which an amount of cash equal to such taxable income would be distributed (without regard to any restrictions on distributions described herein) if, immediately prior to such deemed distribution, the Special Litigation Trust had distributed all of its other assets (valued for this purpose at their tax book value) to the holders of the Special Litigation Trust Interests, taking into account all prior and concurrent distributions from the Special Litigation Trust (including all distributions held in escrow pending the resolution of Disputed Claims). Similarly, taxable loss of the Special Litigation Trust shall be allocated by reference to the manner in which an economic loss would be borne immediately after a liquidating distribution of the remaining Special Litigation Trust Claims. The tax book value of the Special Litigation Trust Claims for this purpose shall equal their fair market value on the Effective Date or, if later, the date such assets were acquired by the Special Litigation Trust, adjusted in either case in accordance with tax accounting principles prescribed by the IRC, the regulations and other applicable administrative and judicial authorities and pronouncements.

c. Other. The Special Litigation Trustee shall file (or cause to be filed) any other statements, returns or disclosures relating to the Special Litigation Trust that are required by any governmental unit.

10. Trust Implementation

On the Effective Date, the Special Litigation Trust shall be established and become effective for the benefit of Allowed Claims in Classes 3 through 180. The Special Litigation Trust Agreement shall be filed in the Plan Supplement and shall contain provisions customary to trust agreements utilized in comparable circumstances, including, but not limited to, any and all provisions necessary to ensure the continued treatment of the Special Litigation Trust as a grantor trust for federal income tax purposes. All parties (including the Debtors, the Special Litigation Trustee and holders of Allowed Claims in Classes 3 through 180 shall execute any documents or other instruments as necessary to cause title to the applicable assets to be transferred to the Special Litigation Trust.

11. Registry of Beneficial Interests

The Special Litigation Trustee shall maintain a registry of the holders of Special Litigation Trust Interests.

12. Termination

The Special Litigation Trust shall terminate no later than the fifth (5th) anniversary of the Effective Date; provided, however, that, on or prior to the date three (3) months prior to such termination, the Bankruptcy Court, upon motion by a party in interest, may extend the term of the Special Litigation Trust if it is necessary to the liquidation of the Special Litigation Trust Claims. Notwithstanding the foregoing, multiple extensions can be obtained so long as Bankruptcy Court approval is obtained at least three (3) months prior to the expiration of each extended term.

13. Net Special Litigation Trust Recovery/Assignment of Claims

a. Net Judgment. Notwithstanding anything contained in the Plan to the contrary, in the event that a defendant in a litigation brought by the Special Litigation Trustee for and on behalf of the Special Litigation Trust (i) is required by a Final Order to pay a Judgment Amount to the Special Litigation Trust and (ii) is permitted by a Final Order to assert a Valid Setoff, (y) such defendant shall be obligated to pay only the excess, if any, of the amount of the Judgment Amount over the Valid Setoff and (z) none of the Special Litigation Trust, the holders or beneficiaries of the Special Litigation Trust Interests shall be entitled to assert a claim against the Debtors or the Reorganized Debtors with respect to the Valid Setoff.

b. Assignment. Notwithstanding anything contained herein to the contrary, in the event that a compromise and settlement of a Special Litigation Trust Claim or a Final Order with respect to a Special Litigation Trust Claim provides for a waiver, subordination or disallowance of a defendant's Claim or Claims against one or more of the Debtors, for purposes of computing amounts of distributions, (i) such claim shall be deemed allowed in the amount determined by the Bankruptcy Court by Final Order, (ii) such defendant shall be deemed to have assigned such Claim or Claims and right to receive distributions in accordance with the Plan to the Special Litigation Trust, and (iii) such defendant shall not be entitled to receive distributions from the Special Litigation Trust on account thereof.

c. Multiple Recoveries. In the event that any avoidance or recovery action commenced in accordance with sections 541, 544, 545, 547, 548, 549, 550, 551 and 553 of the Bankruptcy Code is compromised and settled in connection with a Special Litigation Trust Claim, the proceeds of any recovery, waiver, subordination or disallowance resulting from such compromise and settlement shall be allocated first to the Debtor or Debtors entitled to recovery in accordance with Section 28.1 of the Plan and then to the Litigation Trust.

XII. Equity Trusts

Capitalized terms used throughout this Disclosure Statement are defined in Appendix A: "Material Defined Terms for Enron Disclosure Statement" attached hereto.

A. Preferred Equity Trust

1. Establishment of the Trust

On or after the Confirmation Date, but prior to the Effective Date, the Debtors, on their own behalf and on behalf of holders of Allowed Equity Interests in Class 383, shall execute the Preferred Equity Trust Agreement and shall take all other steps necessary to establish the Preferred Equity Trust. On such date of execution, or as soon as practicable thereafter, including, without limitation, subject to appropriate or required governmental, agency or other consents, and in accordance with and pursuant to the terms of Section 26.4 of the Plan, the Debtors shall issue to the Preferred Equity Trust the Exchanged Enron Preferred Stock subject to the Preferred Equity Trust Agreement. Notwithstanding anything contained herein to the contrary, there shall be separate classes of Preferred Equity Trust Interests that (a) separately reflect the distributions and other economic entitlements and (b) maintain the following order of priority with respect to the separate classes of Exchanged Preferred Equity Interests contributed: (1) Series 1 Exchanged Preferred Stock and Series 2 Exchanged Preferred Stock on a *pari passu* basis; (2) Series 3 Exchanged Preferred Stock; and (3) Series 4 Exchanged Preferred Stock.

2. Purpose of the Preferred Equity Trust

The Preferred Equity Trust shall be established for the sole purpose of holding the Exchanged Enron Preferred Stock in accordance with Treasury Regulation Section 301.7701-4(d) and the terms and provisions of the Preferred Equity Trust Agreement. Without limiting the foregoing, the Preferred Equity Trust Agreement shall provide that, to the extent that the Preferred Equity Trust receives Cash distributions under the Plan in respect of a particular class of Exchanged Preferred Equity Interests, it will redistribute such Cash to the holders of the separate class of Preferred Equity Trust Interests that corresponds to such class of Exchanged Preferred Equity Interests, but in no event will any holder of Preferred Equity Trust Interests receive a distribution of Exchanged Enron Preferred Stock.

3. Funding Expenses of the Preferred Equity Trust

In accordance with the Preferred Equity Trust Agreement and any agreements entered into in connection therewith, on the Effective Date, the Debtors shall have no obligation to provide any funding with respect to any of the Preferred Equity Trust.

4. Transfer of Preferred Stock

a. The issuance of the Exchanged Enron Preferred Stock to the Preferred Equity Trust shall be made, as provided in the Plan, for the benefit of the holders of Allowed Enron Preferred Equity Interests in Class 383.

b. For all federal income tax purposes, all parties (including, without limitation, the Debtors, the Preferred Equity Trustee and the beneficiaries of the Preferred Equity Trust) shall treat the issuance of the Exchanged Enron Preferred Stock to the respective Preferred Equity Trust in accordance with the terms of the Plan, as an issuance to the holders of Allowed Enron Preferred Equity Interests in Class 383, followed by a transfer by such holders to the Preferred Equity Trust and the beneficiaries of the Preferred Equity Trust shall be treated as the grantors and owners thereof.

5. Investment Powers

The right and power of the Preferred Equity Trustee to invest assets transferred to the Preferred Equity Trust, the proceeds thereof, or any income earned by the Preferred Equity Trust, shall be limited to the right and power to invest such assets (pending periodic distributions in accordance with Section 26.6 of the Plan) in Cash Equivalents; provided, however, that (a) the scope of any such permissible investments shall be limited to include only those investments, or shall be expanded to include any additional investments, as the case may be, that a liquidating trust, within the meaning of Treasury Regulation Section 301.7701-4(d) may be permitted to hold, pursuant to the Treasury Regulations, or any modification in the IRS guidelines, whether set forth in IRS rulings, other IRS pronouncements or otherwise, and (b) the Preferred Equity Trustee may expend the assets of the Preferred Equity Trust (i) as reasonably necessary to meet contingent liabilities and to maintain the value of the assets of the Preferred Equity Trust during liquidation, (ii) to pay reasonable administrative expenses (including, but not limited to, any taxes imposed on the Preferred Equity Trust or fees and expenses in connection with litigation), and (iii) to satisfy other liabilities incurred or assumed by the Preferred Equity Trust (or to which the assets are otherwise subject) in accordance with the Plan or the Preferred Equity Trust Agreement; and, provided, further, that, under no circumstances, shall the Preferred Equity Trust segregate the assets of the Preferred Equity Trust on the basis of classification of the holders of Preferred Equity Trust Interests, other than with respect to distributions to be made on account of Disputed Claims and Disputed Equity Interests in accordance with the provisions hereof.

6. Annual Distribution; Withholding

The Preferred Equity Trustee shall distribute at least annually to the holders of each class of Preferred Equity Trust Interests all net cash income plus all net cash proceeds from the liquidation of assets (including as Cash for this purpose, all Cash Equivalents) attributable to such class; provided, however, that the Preferred Equity Trust may retain such amounts (i) as are reasonably necessary to meet contingent liabilities and to maintain the value of the assets of the Preferred Equity Trust during liquidation, (ii) to pay reasonable administrative expenses (including any taxes imposed on the Preferred Equity Trust or in respect of the assets of the Preferred Equity Trust), and (iii) to satisfy other liabilities incurred or assumed by the Preferred Equity Trust (or to which the assets are otherwise subject) in accordance with the Plan or the Preferred Equity Trust Agreement. All such distributions with respect to a given class of Preferred Equity Trust Interests shall be pro rata based on the number of Preferred Equity Trust Interests of such class held by a holder compared with the aggregate number of Preferred Equity Trust Interests of such class outstanding, subject to the terms of the Plan and the respective Preferred Equity Trust Agreement. The Preferred Equity Trustee may withhold from amounts distributable to any Person any and all amounts, determined in the Preferred Equity Trustee's reasonable sole discretion, to be required by any law, regulation, rule, ruling, directive or other governmental requirement. Notwithstanding the foregoing, any distributions to be made on account of the separate classes of Preferred Equity Trust Interests shall be made in the following order of priority with respect to the separate classes of Exchanged Preferred Equity Interests contributed: (1) Series 1 Exchanged Preferred Stock and Series 2 Exchanged Preferred Stock on a *pari passu* basis; (2) Series 3 Exchanged Preferred Stock; and (3) Series 4 Exchanged Preferred Stock.

7. Reporting Duties

a. Federal Income Tax. Subject to definitive guidance from the IRS or a court of competent jurisdiction to the contrary (including the receipt by the Preferred Equity Trustee of a private letter ruling if the Preferred Equity Trustee so requests one, or the receipt of an adverse determination by the IRS upon audit if not contested by the Preferred Equity Trustee), the Preferred Equity Trustee shall file returns for the Preferred Equity Trust as a grantor trust (consisting of separate shares for each class of Exchanged Enron Preferred Stock owned by the Preferred Equity Trust) pursuant to Treasury Regulation Section 1.671-4(a). The Preferred Equity Trustee shall also annually send to each holder of a Preferred Equity Trust Interest a separate statement setting forth the holder's share of items of income, gain, loss, deduction or credit and shall instruct all such holders to report such items on their federal income tax returns.

b. Allocations of Preferred Equity Trust Taxable Income. Allocations of Preferred Equity Trust taxable income shall be determined by reference to the manner in which an amount of cash equal to such taxable income would be distributed (without regard to any restrictions on distributions described herein) if, immediately prior to such deemed distribution, the Preferred Equity Trust had distributed all of its other assets (valued for this purpose at their tax book value) to the holders of the Preferred Equity Trust Interests (treating any holder of a Disputed Claim, for this purpose, as a current holder of a Preferred Equity Trust Interest entitled to distributions), taking into account all prior and concurrent distributions from the Preferred Equity Trust (including all distributions held in escrow pending the resolution of Disputed Claims). Similarly, taxable loss of the Preferred Equity Trust shall be allocated by reference to the manner in which an economic loss would be borne immediately after a liquidating distribution of the remaining assets of the Preferred Equity Trust. The tax book value of the assets of the Preferred Equity Trust for this purpose shall equal their fair market value on the date the Preferred Equity Trust was created or, if later, the date such assets were acquired by the Preferred Equity Trust, adjusted in either case in accordance with tax accounting principles prescribed by the IRC, the regulations and other applicable administrative and judicial authorities and pronouncements.

c. Other. The Preferred Equity Trustee shall file (or cause to be filed) any other statements, returns or disclosures relating to the Preferred Equity Trust that are required by any governmental unit.

8. Trust Implementation

On the Effective Date, the Preferred Equity Trust shall be established and become effective for the benefit of Allowed Enron Preferred Equity Interests in Class 383. The Preferred Equity Trust Agreement shall be filed in the Plan Supplement and shall contain provisions customary to trust agreements utilized in comparable circumstances, including, but not limited to, any and all provisions necessary to ensure the continued treatment of the Preferred Equity Trust as a grantor trust for federal income tax purposes. All parties (including the Debtors, the Preferred Equity Trustee and holders of Allowed Enron Preferred Equity Interests in Class 383) shall execute any documents or other instruments as necessary to cause title to the applicable assets to be transferred to the Preferred Equity Trust.

9. Registry of Beneficial Interests

The Preferred Equity Trustee shall maintain a registry of the holders of Preferred Equity Trust Interests.

10. Termination

The Preferred Equity Trust shall terminate no later than the third (3rd) anniversary of the Confirmation Date; provided, however, that, on or prior to the date three (3) months prior to such termination, the Bankruptcy Court, upon motion by a party in interest, may extend the term of the Preferred Equity Trust if it is necessary to the liquidation of the assets of Preferred Equity Trust. Notwithstanding the foregoing, multiple extensions can be obtained so long as Bankruptcy Court approval is obtained at least three (3) months prior to the expiration of each extended term; provided, however, that the aggregate of all such extensions shall not exceed three (3) years from and after the third (3rd) anniversary of the Confirmation Date.

11. Non-Transferability or Certification

Upon the creation of the Preferred Equity Trust, the Preferred Equity Trust Interests shall be allocated on the books and records of the Preferred Equity Trust to the appropriate holders thereof, but the Preferred Equity Trust Interests shall not be certificated and shall not be transferable by the holder thereof except through the laws of descent or distribution.

B. Common Equity Trust

1. Establishment of the Trusts. On or after the Confirmation Date, but prior to the Effective Date, the Debtors, on their own behalf and on behalf of holders of Allowed Enron Common Equity Interests in Class 384, shall execute the Common Equity Trust Agreement and shall take all other steps necessary to establish the respective Common Equity Trust. On such date of execution, or as soon as practicable thereafter, including, without limitation, subject to appropriate or required governmental, agency or other consents, and in accordance with and pursuant to the terms of Section 27.4 of the Plan, the Debtors shall issue to the Common Equity Trust the Exchanged Enron Common Stock subject to the Common Equity Trust Agreement.

2. Purpose of the Common Equity Trust. The Common Equity Trust shall be established for the sole purpose of holding the Exchanged Enron Common Stock in accordance with Treasury Regulation Section 301.7701-4(d) and the terms and provisions of the Common Equity Trust Agreement. Without limiting the foregoing, the Common Equity Trust Agreement shall provide that, to the extent that the Common Equity Trust receives Cash distributions under the Plan, it will redistribute such Cash to the holders to the Common Equity Trust Interests, but in no event will any holder of Common Equity Trust Interests receive a distribution of Exchanged Enron Common Stock.

3. Funding Expenses of the Common Equity Trust. In accordance with the Common Equity Trust Agreement and any agreements entered into in connection therewith, on the Effective Date, the Debtors shall have no obligation to provide any funding with respect to any of the Common Equity Trust.

4. Transfer of Common Stock

a. The issuance of the Exchanged Enron Common Stock to the Common Equity Trust shall be made, as provided in the Plan, for the benefit of the holders of Allowed Enron Common Equity Interests in Class 384.

b. For all federal income tax purposes, all parties (including, without limitation, the Debtors, the Common Equity Trustee and the beneficiaries of the Common Equity Trust) shall treat the issuance of the Exchanged Enron Common Stock to the respective Common Equity Trust in accordance with the terms of the Plan, as an issuance to the holders of Allowed Enron Common Equity Interests in Class 384, followed by a transfer by such holders to the Common Equity Trust and the beneficiaries of the Common Equity Trust shall be treated as the grantors and owners thereof.

5. Investment Powers. The right and power of the Common Equity Trustee to invest assets transferred to the Common Equity Trust, the proceeds thereof, or any income earned by the Common Equity Trust, shall be limited to the right and power to invest such assets (pending periodic distributions in accordance with Section 27.6 of the Plan) in Cash Equivalents; provided, however, that (a) the scope of any such permissible investments shall be limited to include only those investments, or shall be expanded to include any additional investments, as the case may be, that a liquidating trust, within the meaning of Treasury Regulation Section 301.7701-4(d) may be permitted to hold, pursuant to the Treasury Regulations, or any modification in the IRS guidelines, whether set forth in IRS rulings, other IRS pronouncements or otherwise, and (b) the Common Equity Trustee may expend the assets of the Common Equity Trust (i) as reasonably necessary to meet contingent liabilities and to maintain the value of the assets of the Common Equity Trust during liquidation, (ii) to pay reasonable administrative expenses (including, but not limited to, any taxes imposed on the Common Equity Trust or fees and expenses in connection with litigation), and (iii) to satisfy other liabilities incurred or assumed by the Common Equity Trust (or to which the assets are otherwise subject) in accordance with the Plan or the Common Equity Trust Agreement; and, provided, further, that, under no circumstances, shall the Common Equity Trust segregate the assets of the Common Equity Trust on the basis of classification of the holders of Common Equity Trust Interests, other than with respect to distributions to be made on account of Disputed Claims and Disputed Equity Interests in accordance with the provisions of the Plan.

6. Annual Distribution; Withholding. The Common Equity Trustee shall distribute at least annually to the holders of Common Equity Trust Interests all net cash income plus all net cash proceeds from the liquidation of assets (including as Cash for this purpose, all Cash Equivalents); provided, however, that the Common Equity Trust may retain such amounts (i) as are reasonably necessary to meet contingent liabilities and to maintain the value of the assets of the Common Equity Trust during liquidation, (ii) to pay reasonable administrative expenses (including any taxes imposed on the Common Equity Trust or in respect of the assets of the Common Equity Trust), and (iii) to satisfy other liabilities incurred or assumed by the Common Equity Trust (or to which the assets are otherwise subject) in accordance with the Plan or the Common Equity Trust Agreement. All such distributions shall be pro rata based on the number of Common Equity Trust Interests held by a holder compared with the aggregate number of Common Equity Trust Interests outstanding, subject to the terms of the Plan and the respective Common Equity Trust Agreement. The Common Equity Trustee may withhold from amounts distributable to any Person any and all amounts, determined in the Common Equity Trustee's reasonable sole discretion, to be required by any law, regulation, rule, ruling, directive or other governmental requirement.

7. Reporting Duties

a. Federal Income Tax. Subject to definitive guidance from the IRS or a court of competent jurisdiction to the contrary (including the receipt by the Common Equity Trustee of a private letter ruling if the Common Equity Trustee so requests one, or the receipt of an adverse determination by the IRS upon audit if not contested by the Common Equity Trustee), the Common Equity Trustee shall file returns for the Common Equity Trust as a grantor trust pursuant to Treasury Regulation Section 1.671-4(a). The Common Equity Trustee shall also annually send to each holder of a Common Equity Trust Interest a separate statement setting forth the holder's share of items of income, gain, loss, deduction or credit and shall instruct all such holders to report such items on their federal income tax returns.

b. Allocations of Common Equity Trust Taxable Income. Allocations of Common Equity Trust taxable income shall be determined by reference to the manner in which an amount of cash equal to such taxable income would be distributed (without regard to any restrictions on distributions described in the Plan) if, immediately prior to such deemed distribution, the Common Equity Trust had distributed all of its other assets (valued for this purpose at their tax book value) to the holders of the Common Equity Trust Interests (treating any holder of a Disputed Claim, for this purpose, as a current holder of a Common Equity Trust Interest entitled to distributions), taking into account all prior and concurrent distributions from the Common Equity Trust (including all distributions held in escrow pending the resolution of Disputed Claims). Similarly, taxable loss of the Common Equity Trust shall be allocated by reference to the manner in which an economic loss would be borne immediately after a liquidating distribution of the remaining assets of the Common Equity Trust. The tax book value of the assets of the Common Equity Trust for this purpose shall equal their fair market value on the date the Common Equity Trust was created or, if later, the date such assets were acquired by the Common Equity Trust, adjusted in either case in accordance with tax accounting principles prescribed by the IRC, the regulations and other applicable administrative and judicial authorities and pronouncements.

c. Other. The Common Equity Trustee shall file (or cause to be filed) any other statements, returns or disclosures relating to the Common Equity Trust that are required by any governmental unit.

8. Trust Implementation. On the Effective Date, the Common Equity Trust shall be established and become effective for the benefit of Allowed Enron Common Equity Interests in Class 384. The Common Equity Trust Agreement shall be filed in the Plan Supplement and shall contain provisions customary to trust agreements utilized in comparable circumstances, including, but not limited to, any and all provisions necessary to ensure the continued treatment of the Common Equity Trust as a grantor trust for federal income tax purposes. All parties (including the Debtors, the Common Equity Trustee and holders of Allowed Enron Common Equity Interests in Class 384 shall execute any documents or other instruments as necessary to cause title to the applicable assets to be transferred to the Common Equity Trust.

9. Registry of Beneficial Interests. The Common Equity Trustee shall maintain a registry of the holders of Common Equity Trust Interests.

10. Termination. The Common Equity Trust shall terminate no later than the third (3rd) anniversary of the Confirmation Date; provided, however, that, on or prior to the date three

(3) months prior to such termination, the Bankruptcy Court, upon motion by a party in interest, may extend the term of the Common Equity Trust if it is necessary to the liquidation of the assets of Common Equity Trust. Notwithstanding the foregoing, multiple extensions can be obtained so long as Bankruptcy Court approval is obtained at least three (3) months prior to the expiration of each extended term; provided, however, that the aggregate of all such extensions shall not exceed three (3) years from and after the third (3rd) anniversary of the Confirmation Date.

11. Non-Transferability or Certification. Upon the creation of the Common Equity Trust, the Common Equity Trust Interests shall be allocated on the books and records of the Common Equity Trust to the appropriate holders thereof, but the Common Equity Trust Interests shall not be certificated and shall not be transferable by the holder thereof except through the laws of descent or distribution.

XIII. Securities Laws Matters

Capitalized terms used throughout this Disclosure Statement are defined in Appendix A: "Material Defined Terms for Enron Disclosure Statement" attached hereto.

Holders of Allowed General Unsecured Claims, Allowed Enron Guaranty Claims, Allowed Wind Guaranty Claims, and Allowed Intercompany Claims will receive shares of Prisma Common Stock, CrossCountry Common Stock, and PGE Common Stock to the extent not sold or subject to a purchase agreement in a Sale Transaction, and the holders of Allowed Claims in Classes 3 through 178 will receive Litigation Trust Interests and Special Litigation Trust Interests, pursuant, and subject, to the Plan. The initial issuance of PGE Common Stock, CrossCountry Common Stock, and Prisma Common Stock may not occur for an indeterminate number of months after the Effective Date of the Plan because such issuance will be subject to the following conditions with respect to each issuer of such securities: (i) General Unsecured Claims shall have been allowed in an amount that would result in the distribution of 30% of the common stock of such issuer, (ii) sufficient financial information shall be available for the issuer of such Plan Securities to comply with applicable securities laws, and (iii) the necessary consents to issue such common stock shall have been obtained. Section 1145 of the Bankruptcy Code provides certain exemptions from the securities registration requirements of federal and state securities laws with respect to the distribution of securities under a plan of reorganization.

A. Issuance and Resale of PGE Common Stock, CrossCountry Common Stock, Prisma Common Stock, Litigation Trust Interests and Special Litigation Trust Interests Under the Plan

In reliance upon section 1145 of the Bankruptcy Code, the offer and issuance of PGE Common Stock, CrossCountry Common Stock, and Prisma Common Stock to the holders of the Allowed General Unsecured Claims, Allowed Enron Guaranty Claims, Allowed Wind Guaranty Claims, and Allowed Intercompany Claims, and the issuance of the Litigation Trust Interests and Special Litigation Trust Interests to the holders of Allowed Claims in Classes 3 through 180, will be exempt from the registration requirements of the Securities Act and equivalent provisions in state securities laws. Section 1145(a) of the Bankruptcy Code generally exempts from these registration requirements the issuance of securities if the following conditions are satisfied: (i) the securities are issued or sold under a chapter 11 plan by (A) a debtor, (B) one of its affiliates participating in a joint plan with the debtor, or (C) a successor to a debtor under the plan; and (ii) the securities are issued entirely in exchange for a claim against or interest in the debtor or such affiliate, or are issued principally in such exchange and partly for cash or property. The Debtors believe that the exchange of the Allowed General Unsecured Claims, Allowed Enron Guaranty Claims, Allowed Wind Guaranty Claims, and Allowed Intercompany Claims, and of the Claims in Classes 3 through 180 under the circumstances described in the Plan will satisfy the requirements of section 1145(a) of the Bankruptcy Code.

The PGE Common Stock, CrossCountry Common Stock, Prisma Common Stock, Litigation Trust Interests, and Special Litigation Trust Interests will be deemed to have been issued in a public offering under the Securities Act and, therefore, may be resold by any holder thereof without registration under the Securities Act pursuant to the exemption provided by section 4(1) thereof, unless the holder is an "underwriter" with respect to such securities, as that term is defined in section 1145(b)(1) of the Bankruptcy Code. In addition, the PGE Common Stock, CrossCountry Common Stock, Prisma Common Stock, Litigation Trust Interests, and Special Litigation Trust Interests generally may be resold by the holders thereof without registration under state securities or "blue sky" laws pursuant to various exemptions provided by the respective laws of the individual states. However, holders of PGE Common Stock, CrossCountry Common Stock, Prisma Common Stock, Litigation Trust Interests, and Special Litigation Trust Interests are advised to consult with their own counsel as to the availability of any such exemption from registration under federal securities laws and any relevant state securities laws in any given instance and as to any applicable requirements or conditions to the availability thereof.

Section 1145(b)(i) of the Bankruptcy Code defines "underwriter" for purposes of the Securities Act as one who (a) purchases a claim or interest with a view to distribution of any security to be received in exchange for the claim or interest, (b) offers to sell securities issued under a plan for the holders of such securities, or (c) offers to buy securities issued under a plan from persons receiving such securities, if the offer to buy is made with a view to distribution of such securities and under an agreement made in connection with the plan, with the consummation of the plan, or with the offer or sale of securities under the plan, or (d) is an issuer of the securities within the meaning of section 2(a)(11) of the Securities Act.

An entity is not an "underwriter" under section 2(a)(11) of the Securities Act with regard to securities received under Section 1145(a)(1), in "ordinary trading transactions" made on a national securities exchange or a NASDAQ market. However, there can be no assurances that such securities will be listed on an exchange or NASDAQ market. What constitutes "ordinary trading transactions" within the meaning of section 1145 of the Bankruptcy Code is the subject of interpretive letters by the staff of the SEC. Generally, ordinary trading transactions are those that do not involve (i) concerted activity by recipients of securities under a plan of reorganization, or by distributors acting on their behalf, in connection with the sale of such securities, (ii) use of informational documents in connection with the sale other than the disclosure statement relating to the plan, any amendments thereto, and reports filed by the issuer with the SEC under the Exchange Act, or (iii) payment of special compensation to brokers or dealers in connection with the sale.

With respect to clause (d) in the third paragraph of this Section XIII.A., "Issuance and Resale of PGE Common Stock, CrossCountry Common Stock, Prisma Common Stock, Litigation Trust Interests and Special Litigation Trust Interests Under the Plan", an "issuer" of PGE Common Stock, CrossCountry Common Stock, Prisma Common Stock, Litigation Trust Interests, or Special Litigation Trust Interests includes any person who, directly or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control with, an issuer of PGE Common Stock, CrossCountry Common Stock, Prisma Common Stock, the Litigation Trust Interests, or Special Litigation Trust Interests. "Control" (as defined in Rule 405 under the Securities Act) means the possession, whether directly or indirectly, of the power to direct or cause the direction of the management and policies of a person, whether through the ownership of voting securities, by contract or otherwise. Accordingly, an officer, director or trustee (if applicable) of an issuer of PGE Common Stock, CrossCountry Common Stock, Prisma Common Stock, Litigation Trust Interests, or Special Litigation Trust Interests may be deemed to be a "control" person of an issuer of PGE Common Stock, CrossCountry Common Stock, Prisma Common Stock, Litigation Trust Interests, or Special Litigation Trust Interests, respectively, particularly if the management position or directorship is coupled with ownership of a significant percentage of the voting securities of such issuer. Additionally, the legislative history of section 1145 of the Bankruptcy Code provides that a creditor who receives at least 10% of the voting securities of an issuer under a plan of reorganization will be presumed to be a statutory underwriter within the meaning of section 1145(b)(i) of the Bankruptcy Code.

The Debtors have begun the process of dissolving certain non-Debtor subsidiaries. In conjunction with these dissolutions, in some instances, the dissolved entity has transferred, or will transfer, to its creditors Claims that the dissolved entity held against one or more of the Debtors. For purposes of determining whether a recipient of Plan Securities with respect to such Claims is an "issuer" of Plan Securities under section 1145(b)(1) of the Bankruptcy Code, the new holder of such Claims will be deemed to have the same status as the dissolved entity. Accordingly, even if the holder of such Claims is not controlling, controlled by, or under common control with PGE, CrossCountry, or Prisma, it may be deemed an underwriter of the Plan Securities received with respect to such Claims.

Resales of PGE Common Stock, CrossCountry Common Stock, Prisma Common Stock, Litigation Trust Interests, or Special Litigation Trust Interests by persons deemed to be statutory underwriters will not be exempt from the registration requirements under the Securities Act or other applicable law by virtue of section 1145 of the Bankruptcy Code. Because the issuers of the PGE Common Stock, CrossCountry Common Stock, Prisma Common Stock, Litigation Trust Interests, and Special Litigation Trust Interests do not propose to register any of the PGE Common Stock, CrossCountry Common Stock, Prisma Common Stock, Litigation Trust Interests, and Special Litigation Trust Interests under the Securities Act, persons deemed to be statutory underwriters must either have the PGE Common Stock, CrossCountry Common Stock, Prisma Common Stock, Litigation Trust Interests, or Special Litigation Trust Interests, as the case may be, held by them registered for resale with the SEC or use an available exemption from registration.

Under certain circumstances, persons having a control relationship with the applicable issuer of the PGE Common Stock, CrossCountry Common Stock, Prisma Common Stock, Litigation Trust Interests, or Special Litigation Trust Interests may be entitled to resell their securities pursuant to the limited safe harbor resale provisions of Rule 144 of the Securities Act, to the extent available, and in compliance with applicable state and foreign securities laws. Generally, Rule 144 of the Securities Act provides that persons who are affiliates of an issuer who resell securities will not be deemed to be underwriters if certain conditions are met. These conditions include the requirement that current public information with respect to the issuer be available, a limitation as to the amount of securities that may be sold in any three month period, the requirement that the securities be sold in a "brokers transaction" or in a transaction directly with a "market maker" and that notice of the resale be filed with the SEC. The Debtors cannot assure, however, that adequate current public information will exist with respect to any issuer of PGE Common Stock, CrossCountry Common Stock, Prisma Common Stock, Litigation Trust Interests, or Special Litigation Trust Interests and, therefore, that the safe harbor provisions of Rule 144 of the Securities Act will be available.

Pursuant to the Plan, certificates evidencing PGE Common Stock, CrossCountry Common Stock, Prisma Common Stock, Litigation Trust Interests, or Special Litigation Trust Interests received by any person whom the issuer of the PGE Common Stock, CrossCountry Common Stock, Prisma Common Stock, Litigation Trust Interests, or Special Litigation Trust Interests determines to be a person deemed to be a statutory underwriter will bear a legend substantially in the form below:

"THE SECURITIES EVIDENCED BY THIS CERTIFICATE HAVE NOT BEEN REGISTERED UNDER THE SECURITIES ACT OF 1933, AS AMENDED, OR UNDER THE SECURITIES LAWS OF ANY STATE OR OTHER JURISDICTION AND MAY NOT BE SOLD, OFFERED FOR SALE OR OTHERWISE TRANSFERRED UNLESS REGISTERED OR QUALIFIED UNDER SAID ACT AND APPLICABLE STATE SECURITIES LAWS OR UNLESS THE [COMPANY] [TRUSTEE] RECEIVES AN OPINION OF COUNSEL REASONABLY SATISFACTORY TO IT THAT SUCH REGISTRATION OR QUALIFICATION IS NOT REQUIRED."

Any Person entitled to receive PGE Common Stock, CrossCountry Common Stock, Prisma Common Stock, Litigation Trust Interests, or Special Litigation Trust Interests whom the issuer of PGE Common Stock, CrossCountry Common Stock, Prisma Common Stock, Litigation Trust Interests, or Special Litigation Trust Interests determines to be a person deemed to be a statutory underwriter may instead receive certificates evidencing PGE Common Stock, CrossCountry Common Stock, Prisma Common Stock, Litigation Trust Interests, or Special Litigation Trust Interests without such legend if, prior to the distribution of such securities, such Person delivers to such issuer (i) an opinion of counsel reasonably satisfactory to such issuer to the effect that the PGE Common Stock, CrossCountry Common Stock, Prisma Common Stock, Litigation Trust Interests, or Special Litigation Trust Interests to be received by such Person are not subject to the restrictions applicable to "underwriters" under section 1145 of the Bankruptcy Code and may be sold without registration under the Securities Act and (ii) a certification that such person or entity is not an "underwriter" within the meaning of section 1145 of the Bankruptcy Code.

Any holder of a certificate evidencing PGE Common Stock, CrossCountry Common Stock, Prisma Common Stock, Litigation Trust Interests, or Special Litigation Trust Interests bearing such legend may present such certificate to the transfer agent for such securities for exchange for one or more new certificates not bearing such legend or for transfer to a new holder without such legend at such time as (i) the applicable securities are sold pursuant to an effective registration statement under the Securities Act, (ii) such holder delivers to the issuer of the applicable securities an opinion of counsel reasonably satisfactory to such issuer to the effect that such securities are no longer subject to the restrictions applicable to "underwriters" under section 1145 of the Bankruptcy Code, or (iii) such holder delivers to the issuer of the applicable securities an opinion of counsel reasonably satisfactory to such issuer to the effect that such securities are no longer subject to such restrictions pursuant to an exemption under the Securities Act and such securities may be sold without registration under the Securities Act or to the effect that such transfer is exempt from registration under the Securities Act, in which event the certificate issued to the transferee shall not bear such legend.

IN VIEW OF THE COMPLEX, SUBJECTIVE NATURE OF THE QUESTION OF WHETHER A RECIPIENT OF PGE COMMON STOCK, CROSSCOUNTRY COMMON STOCK, PRISMA COMMON STOCK, LITIGATION TRUST INTERESTS, OR SPECIAL LITIGATION TRUST INTERESTS MAY BE AN UNDERWRITER OR AN AFFILIATE OF AN ISSUER, THE DEBTORS MAKE NO REPRESENTATIONS CONCERNING THE RIGHT OF ANY PERSON TO TRADE IN SECURITIES TO BE DISTRIBUTED PURSUANT TO THE PLAN. ACCORDINGLY, THE DEBTORS RECOMMEND THAT POTENTIAL RECIPIENTS OF PGE COMMON STOCK, CROSSCOUNTRY COMMON STOCK, PRISMA COMMON STOCK, LITIGATION TRUST INTERESTS, AND SPECIAL LITIGATION TRUST INTERESTS CONSULT THEIR OWN COUNSEL CONCERNING WHETHER THEY MAY FREELY TRADE SUCH PGE COMMON STOCK, CROSSCOUNTRY COMMON STOCK, PRISMA COMMON STOCK, LITIGATION TRUST INTERESTS, OR SPECIAL LITIGATION TRUST INTERESTS.

B. Remaining Asset Trust, Preferred Equity Trust, Common Equity Trust and Operating Trusts

The interests in the Remaining Asset Trust, Preferred Equity Trust and Common Equity Trust and, if created, the Operating Trusts, will be allocated on the Effective Date to the applicable holders. Such interests will not be certificated or transferable, except through the laws of descent or distribution. Distributions, if any, to holders of the interests in the Remaining Asset Trust, Preferred Equity Trust, and Common Equity Trust will be limited to cash.

XIV. Risk Factors and Other Factors to be Considered

Capitalized terms used throughout this Disclosure Statement are defined in Appendix A: "Material Defined Terms for Enron Disclosure Statement" attached hereto.

PRIOR TO VOTING TO ACCEPT OR REJECT THE PLAN, HOLDERS OF IMPAIRED CLAIMS ENTITLED TO VOTE ON THE PLAN SHOULD READ AND CAREFULLY CONSIDER EACH OF THE FACTORS SET FORTH BELOW, AS WELL AS OTHER INFORMATION SET FORTH IN THIS DISCLOSURE STATEMENT AND THE DOCUMENTS DELIVERED TOGETHER HEREWITH AND/OR INCORPORATED BY REFERENCE HEREIN.

THE RISKS AND UNCERTAINTIES DESCRIBED BELOW SHOULD NOT BE REGARDED AS CONSTITUTING THE ONLY RISKS INVOLVED IN CONNECTION WITH THE PLAN AND ITS IMPLEMENTATION.

A. Bankruptcy Risks

1. Risk of Non-Confirmation of the Plan

Although the Debtors believe that the Plan will satisfy all requirements necessary for confirmation by the Bankruptcy Court (including, without limitation, satisfaction of secured, priority and administrative claims in accordance with the Bankruptcy Code), there can be no assurance that the Bankruptcy Court will reach the same conclusion. Moreover, there can be no assurance that modifications to the Plan will not be required for confirmation or that such modifications will not necessitate the re-solicitation of votes. In particular, the Plan embodies various settlements and compromises and there can be no assurance that the Bankruptcy Court will approve such settlements and compromises as part of the confirmation of the Plan.

2. Non-Consensual Confirmation

In the event any impaired Class of Claims does not accept the Plan, the Bankruptcy Court may nevertheless confirm the Plan at the Debtors' request if at least one impaired Class has accepted the Plan (such acceptance being determined without including the vote of any "insider" in such Class), and as to each impaired Class that has not accepted the Plan, if the Bankruptcy Court determines that the Plan "does not discriminate unfairly" and is "fair and equitable" with respect to the dissenting impaired classes. Refer to Section XIX., "Confirmation Of The Plan" for further information. The Debtors believe that the Plan satisfies these requirements.

3. Risk of Non-Occurrence or Delayed Occurrence of the Effective Date

Although the Debtors believe that the Effective Date will occur after the Confirmation Date following satisfaction of any applicable conditions precedent, there can be no assurance as to the timing of the Effective Date. If the conditions precedent to the Effective Date set forth in the Plan have not occurred or been waived by the Debtors, then the Confirmation Order will be vacated, in which event no distributions would be made under the Plan, the Debtors and all holders of Claims and Equity Interests would be restored to the status quo ante as of the day immediately preceding the Confirmation Date, and the Debtors' obligations with respect to Claims and Equity Interests would remain unchanged. Furthermore, the Effective Date may be delayed for several months pending the fulfillment of such conditions.

4. Delayed Distribution or Non-Distribution of Plan Securities

The Prisma Common Stock, CrossCountry Common Stock, and PGE Common Stock will not be distributed to the holders of the Allowed General Unsecured Claims, Allowed Enron Guaranty Claims, Allowed Wind Guaranty Claims, and Allowed Intercompany Claims until sufficient General Unsecured Claims have been allowed to permit a distribution of 30% of such securities and any necessary consents have been obtained to issue such securities. Refer to Section XIII., "Securities Laws Matters" for further information. Furthermore, the Prisma

Common Stock, CrossCountry Common Stock, or PGE Common Stock will never be distributed if a Sale Transaction with regard to 100% of the equity, or all or substantially all of the assets of, Prisma, CrossCountry, or PGE, as the case may be, has occurred prior to distribution, but the net proceeds from such sale will be included in the Creditor Cash available for distribution pursuant to the terms of the Plan. There can be no assurance of when sufficient Claims will be allowed for the distribution of 30% of the Prisma Common Stock, CrossCountry Common Stock, and PGE Common Stock and as to when or if any of the necessary consents can be obtained to prevent the exercise of any rights upon a change of ownership or control of Prisma, CrossCountry, or PGE. Accordingly, there can be no assurances as to when, or if, Prisma Common Stock, CrossCountry Common Stock, and PGE Common Stock will ever be distributed to holders of Allowed General Unsecured Claims, Allowed Enron Guaranty Claims, Allowed Wind Guaranty Claims, and Allowed Intercompany Claims.

5. Severability

As set forth in Section 39.12 of the Plan, the Debtors may choose to go forward with confirmation of the Plan with regard to certain Debtors' estates, but may choose to exclude certain Debtors' estates from confirmation. If one or more Debtors are severed from confirmation of the Plan, the amount of distributions to Creditors pursuant to the Plan could be affected. In addition, any Debtor severed from confirmation of the Plan must either bear the cost of confirming its own chapter 11 plan or convert to chapter 7 and bear the costs of a chapter 7 trustee.

6. Reserve for Disputed Claims.

The Plan provides that the Disbursing Agent shall reserve and hold in escrow for the benefit of each holder of a Disputed Claim, Cash, Plan Securities, Operating Trust Interests, Remaining Asset Trust Interests, Litigation Trust Interests and Special Litigation Trust Interests and any dividends, gains or income attributable thereto until such Disputed Claim becomes an Allowed Claim. The terms under which, and vehicle in which, the Disbursing Agent will hold and administer these items have not been determined. It is not known whether such terms will have any impact on the other holders of Plan Securities, Operating Trust Interests, Remaining Asset Trust Interests, Litigation Trust Interests and Special Litigation Trust Interests.

B. Negative Impact of Prepetition Activities

1. Inability to Rely on Financial Statements

As discussed in Section II.B., "Representations", ENE has publicly stated that its financial statements filed with the SEC for the fiscal years ended 1997 through 2000, and for the first three quarters of 2001, should not be relied upon. In addition, since the bankruptcy, ENE has not engaged an independent auditor and has not published ENE financial statements. The inability to rely on past financial statements, the lack of an ENE auditor, and the resignation or termination of numerous Enron Companies' employees have and may continue to have a negative impact on the Enron Companies, including the Operating Entities, and adversely affect the value recovered on other assets.

2. Government Investigations and Litigation

The existence of ongoing litigation and governmental investigations regarding prepetition activities have and may continue to have a negative impact on the Enron Companies, including the Operating Entities, or the value of the recovery on any other assets. The Enron Companies have been the subject of numerous lawsuits, including class actions, derivative lawsuits, and arbitration proceedings in the United States, and in various jurisdictions around the world. ENE and certain of its current and former employees are also the subject of a number of governmental investigations, including by the U.S. Congress, DOJ, SEC, Office of Public Utility Counsel, EPA, and FERC. There can be no assurance that additional claims or investigations will not be made against the Enron Companies, including the Operating Entities, relating to the prepetition activities of ENE and its Affiliates. It is impossible to predict or determine the final outcome or resolution of any of the unresolved proceedings. However, such investigations may result in, among other things, assessment of fines and penalties and/or criminal charges against all or some of the Enron Companies and their current or former employees. The Debtors assert that, in accordance with the priority scheme under the Bankruptcy Code, any such claims against the Debtors are subordinate to General Unsecured Claims. In addition, the DOJ could declare certain or all of the assets of the Enron Companies subject to criminal forfeiture by the federal government. Refer to Sections IV.C.1., "Pending Litigation", IV.C.2., "Government Investigations" and IX.C., "Historical Financials, Projections and Valuation" for further information.

3. Financing Transactions

As part of their business, the Enron Companies utilized a number of on- and off-balance sheet financing structures. As part of a number of these transactions, certain assets may have been transferred to or otherwise become subject to restrictions associated with the financing structures. It is important to note that there is no guarantee that any value from these assets will inure to the benefit of the Debtors' estates. Additionally, there are significant liabilities associated with the financing transactions and several billion dollars in claims have been filed against Debtors in connection with these transactions. Refer to Section III.F., "Debtors' Financing Transactions" for further information.

C. Variance from Valuations, Estimates and Projections

The estimated recoveries and valuations set forth in this Disclosure Statement and the projections, valuations and estimates set forth in Appendix C: "Estimated Assets, Claims and Distributions", Appendix G: "Reorganized Debtors' Budget", Appendix H: "PGE Financial Projections – 2003-2006", Appendix J: "CrossCountry Financial Projections – 2003-2006", Appendix K: "Prisma Financial Projections – 2004-2006", and Appendix L: "Liquidation Analysis" are highly speculative and based on information available at the time that each analysis was prepared.

In addition, the Debtors assert that, in accordance with the priority scheme under the Bankruptcy Code, the Subordinated Claims (which include Classes 376-382) are subordinate to General Unsecured Claims, Enron Guaranty Claims Wind Guaranty Claims and Intercompany Claims. Although this is the Debtors contention, the Bankruptcy Court may ultimately conclude that one or more of the Subordinated Claims should not be subordinated.

Actual results will vary **and may vary** materially from those reflected herein. Refer to the entirety of this Section XIV., "Risk Factors and Other Factors to be Considered" for a discussion of potential risks and variances.

1. Forward Looking Statements

Each of the estimated recoveries and valuations set forth in this Disclosure Statement and the projections, valuations and estimates set forth in Appendix C: "Estimated Assets, Claims and Distributions", Appendix G: "Reorganized Debtors' Budget", Appendix H: "PGE Financial Projections – 2003-2006", Appendix J: "CrossCountry Financial Projections – 2003-2006", Appendix K: "Prisma Financial Projections – 2004-2006", and Appendix L: "Liquidation Analysis" are based, in large part, on forward looking statements.

Forward-looking statements are statements of expectations, beliefs, plans, objectives, assumptions, projections, and future events or performance. These statements, estimates and projections may or may not prove to be correct. Actual results could differ materially from those reflected in the forward-looking statements. Forward-looking statements are not guarantees of future performance and involve risks and uncertainties that could cause actual results or outcomes to differ materially from those expressed. Such risks and uncertainties include, without limitation: risks inherent in the Chapter 11 process, such as the non-confirmation of the Plan, non-occurrence or delayed occurrence of the Effective Date, or delayed distribution or non-distribution of Plan Securities; the uncertain outcomes of ongoing litigation and governmental investigations involving the Operating Entities and the Debtors, including those involving the U.S. Congress, DOJ, SEC, Office of Public Utility Counsel, EPA, and FERC; the effects of negative publicity on the Operating Entities' business opportunities; the effects of the departure of past and present employees of the Debtors; the uncertain resolution of SPE issues; the preliminary and uncertain nature of valuations and estimates contained in the Plan; financial and operating restrictions that may be imposed on an Operating Entity and its subsidiaries if ENE is required to register under PUHCA; potential environmental liabilities; increasing competition and operational hazards faced by the Debtors and Operating Entities; the lack of independent operating history of the Operating Entities; and economic, political, regulatory, and legal risks affecting the finances and operations of the Operating Entities.

The Debtors, the Reorganized Debtors, PGE, CrossCountry, Prisma, and the other Enron Companies undertake no obligation to update any forward-looking statement included in the projections to reflect the occurrence of unanticipated events. New factors emerge from time to time and it is not possible to predict all such factors, nor can the impact of any such factor be assessed.

2. Estimated Recoveries

The recovery estimates set forth herein are based on various estimates and assumptions. For example, if the estimated amount of Allowed Claims relied upon to calculate the estimated recoveries ultimately varies significantly from the actual amount of Allowed Claims, then actual creditor recoveries will vary significantly as well. Similarly, as the estimated amount of Allowed Claims is a forward-looking statement based upon information available to the Debtors as of June 1, 2003, the actual results may vary significantly as Claims are Allowed or otherwise resolved over time.

Over 24,000 proofs of claim have been filed in these Chapter 11 Cases. The aggregate amount of Claims filed and scheduled exceeds $900 billion, including duplication, but excluding any estimated amounts for the approximately 5,800 filed unliquidated Claims. These unliquidated Claims currently render it impossible for the Debtors to determine the maximum amount of their potential liability. In addition, the priority of claims and assertions by certain parties as to their entitlement to liens and/or constructive trusts may change the value available to satisfy Allowed General Unsecured Claims.

3. Valuations

If the estimated value of assets (including, but not limited to, estimates of available Creditor Cash, recoveries on the Remaining Assets, and the valuation of the stock in PGE, CrossCountry and Prisma to be distributed to Creditors) set forth herein ultimately vary significantly from actual results, then actual creditor recoveries will vary significantly as well. Similarly, as the estimated value of assets are forward-looking statements based upon information available to the Debtors as of July 1, 2003 (except in certain circumstances, as to which information was updated through August 11, 2003), the actual results may vary significantly.

a. Remaining Assets. With respect to the Remaining Assets, the estimated recoveries, valuations and projections are based, in part, on estimated proceeds generated by a sale or other disposition of substantially all of these assets. Many of these assets have been on the market or the subject of inquiries since the Initial Petition Date, but have not been sold for a variety of reasons, including, but not limited to, poor market conditions and the need to resolve complex ownership issues, pending litigation or government investigations, tax issues, and consent issues. In some cases, the Reorganized Debtors will be attempting to sell non-controlling financial interests for which a limited market exists. Due to the inherent uncertainties associated with selling these assets as a result of the issues identified above, there can be no assurance that these assets will be sold at presently estimated prices or at presently estimated times, if at all. Similarly, the recoveries of the Debtors (or the Reorganized Debtors, as the case may be) against counterparties on trading contracts are dependent on the creditworthiness and ability to pay of the counterparties.

b. Creditor Cash. The inability to sell or otherwise convert the Remaining Assets to cash may materially impact, among other things, the value of the Plan Currency. As a result of the foregoing, the Creditor Cash available for distribution as a result of liquidation of the Remaining Assets may be impacted.

c. Operating Entities Generally. Estimates of value of the Operating Entities do not purport to be appraisals nor do they necessarily reflect the values that may be realized if assets are sold. The estimates of value represent hypothetical equity values assuming the implementation of each of the Operating Entities' business plan, as well as other significant assumptions. Such estimates were developed solely for purposes of formulating and negotiating the Plan and analyzing the projected recoveries thereunder. Any estimated equity value is highly dependent upon achieving the future financial results set forth in the projections for each of the Operating Entities, as well as the realization of certain other assumptions that are not guaranteed.

The valuations of each of the Operating Entities set forth herein represent estimated values and do not necessarily reflect values that could be attainable in public or private markets for the Operating Entities or their constituent assets. The equity value ascribed in each of the valuation analyses does not purport to be an estimate of the market value of stock to be distributed pursuant to the Plan. Such trading value, if any, may be materially different from the equity value associated with the valuation analysis.

The valuations of each of the Operating Entities set forth herein do not reflect any dilution resulting from any long-term equity incentive compensation plan(s) as may be adopted by the Operating Entities. However, it is anticipated that the impact of any such plan(s) to be adopted by PGE, CrossCountry and Prisma will, in the aggregate, represent less than 1% of the overall value to be distributed under the Plan. In addition, the valuations of each of the Operating Entities does not include the anticipated costs associated with the voluntary termination of the ENE Cash Balance Plan.

d. PGE. The valuation of PGE set forth herein assumes that the current regulatory environment remains unchanged. However, PGE operates in a heavily regulated industry. Changes to the current regulatory environment may have a material adverse impact on PGE's actual results. For further discussion on these and other risks attendant with PGE and the electric utility industry, refer to the entirety of this Section XIV., "Risk Factors and Other Factors to be Considered", as well as Section VIII., "Portland General Electric Company".

e. CrossCountry. The valuation of CrossCountry set forth herein assumes certain levels of rates for the transportation of natural gas as set by FERC. Such rates are highly regulated and subject to periodic changes. There is no guarantee that the current rate levels will not change materially in the future or will provide adequate reimbursement for the services provided by CrossCountry and its subsidiaries. Any such changes are entirely beyond CrossCountry's control and may have a material adverse impact on actual results. Further, CrossCountry operates in a heavily regulated industry. In the ordinary course of its business, CrossCountry is subject regularly to inquiries, investigations and audits by federal and state agencies that oversee various natural gas pipeline regulations. Changes to the current regulatory environment may have a material adverse impact on CrossCountry's actual results. In addition, the valuation of CrossCountry assumes that the Pipeline Businesses will successfully complete ongoing expansion projects, and that certain receivables due from ENE or its Affiliates will be treated in accordance with the Plan. If the expansions are not completed as planned or if the receivables due from ENE are not ultimately recoverable under the Plan, there may be a material adverse impact on CrossCountry's actual results. For further discussion on these and other risks attendant with CrossCountry and the natural gas pipeline industry, refer to the entirety of this Section XIV., "Risk Factors and Other Factors to be Considered", as well as Section IX., "CrossCountry Energy Corp."

f. Prisma. The valuation of Prisma set forth herein assumes certain levels of tariffs or rates of return for the constituent assets. Such rates are highly regulated, subject to periodic changes, and in certain circumstances are the outcome of political processes in the subject jurisdictions. There is no guarantee that the current rate levels will not change materially in the future or will provide adequate reimbursement for the services provided by Prisma and its subsidiaries. Any such changes are entirely beyond Prisma's control and may have a material adverse impact on actual results. Further, as Prisma operates primarily in foreign jurisdictions, such political processes often lead to greater volatility in regulatory outcomes than might occur in the United States. Additionally, operations in the emerging markets are generally subject to greater risk of global economic slowdown, political uncertainty, currency devaluation, exchange controls and the ability to enforce and defend legal and contractual rights than are domestic companies. Such risk factors may also have a material adverse impact on Prisma's actual results. For further discussion on these and other risks attendant with Prisma and the industries in which it is involved, refer to the entirety of this Section XIV., "Risk Factors and Other Factors to be Considered", as well as Section X., "Prisma Energy International Inc."

4. Financial Projections

The Debtors have prepared the projections set forth in Appendix H: "PGE Financial Projections – 2003-2006", Appendix I: "CrossCountry Historical Financials" and Appendix K: "Prisma Financial Projections – 2004-2006" (as well as incorporated into the estimated creditor recoveries and valuations included herein) based on certain assumptions that they believe are reasonable under the circumstances. Certain assumptions are described in each of the relevant Appendices. The projections have not been compiled or examined by independent accountants. The Debtors make no representations regarding the accuracy of the projections or any ability to achieve forecasted results. Many of the assumptions underlying the projections are subject to significant uncertainties. Inevitably, some assumptions will not materialize, and unanticipated events and circumstances may affect the ultimate financial results. Therefore, the actual results achieved will vary from the forecasts, and the variations may be material. In evaluating the Plan, Creditors are urged to examine carefully all of the assumptions underlying the financial projections.

5. Reorganized Debtors' Budget

The Debtors have prepared the Reorganized Debtors' Budget attached as Appendix G: "Reorganized Debtors' Budget" based on certain assumptions that they believe are reasonable under the circumstances. Certain assumptions are described in Appendix G: "Reorganized Debtors' Budget". The underlying projections have not been compiled or examined by independent accountants. The Debtors make no representations regarding the accuracy of the projections or the Reorganized Debtors' ability to achieve forecasted results. Many of the assumptions underlying the projections are subject to significant uncertainties. Inevitably, some assumptions will not materialize, and unanticipated events and circumstances may affect the ultimate financial results. Therefore, the actual results achieved will vary from the forecasts, and the variations may be material. In evaluating the Plan, Creditors are urged to examine carefully all of the assumptions underlying the Reorganized Debtors' Budget.

6. Liquidation Analysis

The Debtors have prepared the Liquidation Analysis attached as Appendix L: "Liquidation Analysis" based on certain assumptions that they believe are reasonable under the circumstances. Those assumptions that the Debtors consider significant are described in the Liquidation Analysis. The underlying projections have not been compiled or examined by independent accountants. The Debtors make no representations regarding the accuracy of the projections or a chapter 7 trustee's ability to achieve forecasted results. Many of the assumptions underlying the projections are subject to significant uncertainties. Inevitably, some assumptions will not materialize and unanticipated events and circumstances may affect the ultimate financial results. In the event these Chapter 11 Cases are converted to chapter 7, actual results may vary materially from the estimates and projections set forth in the Liquidation Analysis. As such, the Liquidation Analysis is speculative in nature. In evaluating the Plan, Creditors are urged to examine carefully all of the assumptions underlying the Liquidation Analysis.

D. Control Group Risks

1. ENE Cash Balance Plan

As of December 31, 2002, the assets of the ENE Cash Balance Plan were less than the present value of all accrued benefits by approximately $182 million on a plan termination basis. The PBGC has filed unliquidated claims in the Debtors' bankruptcy cases for PBGC insurance premiums and unpaid minimum funding contributions. The PBGC has filed liquidated claims for unfunded benefit liabilities under the ENE Cash Balance Plan and the defined benefit plans of other ENE related companies (including PGE) for unfunded benefit liabilities in an aggregate amount equal to $424.1 million, including $352.3 million for the ENE Cash Balance Plan and $57.5 million related to the Portland General Holdings, Inc. Pension Plan. PBGC has also informally alleged that its unfunded benefit liability claim in respect of the ENE Cash Balance Plan claim could increase by as much as 100%. The Debtors reserve the right to object to these claims. Refer to Section IV.A.8.d., "Pension Benefits/Pension Benefit Guaranty Corporation" for further information.

Upon termination of an underfunded pension plan, which could be initiated by PBGC or ENE, all of the members of the ERISA controlled group of the plan sponsor (ENE) become jointly and severally liable for the plan's underfunding. If PBGC makes a demand for payment against one or more members of the controlled group and the payment is not made, a lien in favor of PBGC automatically arises against all of the assets of that member of the controlled group. The amount of the lien is equal to the lesser of the underfunding or 30% of the aggregate net worth of all of the members of the controlled group. Prisma, CrossCountry, and PGE are members of the ENE ERISA controlled group of corporations as long as ENE, or any of its controlled group members, holds at least 80% of the outstanding stock of Prisma, CrossCountry, or PGE. ENE has agreed, subject to certain limitations, pursuant to the terms of the CrossCountry Contribution and Separation Agreement, to indemnify CrossCountry for certain liabilities arising out of any employee benefit plan sponsored by ENE that are imposed or assessed under Title IV of ERISA against CrossCountry or any CrossCountry Asset, as a result of a distress termination of the ENE Cash Balance Plan. The foregoing indemnification does not include contribution obligations in respect of the ENE Cash Balance Plan underfunding, which may result from ENE's voluntary termination of the ENE Cash Balance Plan. Among other limitations, the indemnity does not relieve any indemnified party from the obligation to make payments pursuant to any order of the Bankruptcy Court, or any agreement between any ENE company and CrossCountry, Prisma, PGE or any CrossCountry Asset or Prisma Asset expected to be contributed to those entities, relating to the allocation of costs of providing employee benefits to the employees of such companies. ENE expects to provide similar indemnification to PGE and Prisma pursuant to separation agreements to be negotiated.

ENE intends to seek the approval of the Bankruptcy Court to fund certain benefits under the ENE Cash Balance Plan and to terminate the plan in a manner that should eliminate PBGC's claims. There can be no assurance that the funding and termination of the ENE Cash Balance Plan will be approved, or that upon approval ENE will have the ability to obtain funding for accrued benefits on acceptable terms. Moreover, if the ENE Cash Balance Plan is terminated, ENE may seek funding contributions from each member of its controlled group of corporations that employs, or employed, individuals who are, or were, covered under the ENE Cash Balance Plan. It is possible that, when the ENE Cash Balance Plan is terminated the CrossCountry Assets and/or the Prisma Assets could be charged with additional funding contributions under the ENE Cash Balance Plan. For example, if at the time of the termination of the ENE Cash Balance Plan, the total unfunded benefit liabilities are assessed at $220 million, the share of such liability allocable to the CrossCountry Assets would be approximately $30.0 million. Similarly, the share of such liability allocable to the Prisma Assets would be $4.3 million. ENE cannot predict at this time the exact date on which the ENE Cash Balance Plan will be terminated and whether or not the CrossCountry Assets and/or the Prisma Assets will be charged with additional contributions to the ENE Cash Balance Plan. The value of the Operating Entities and the Remaining Assets may be adversely affected if the ENE Cash Balance Plan is, or is not, fully funded and terminated.

2. ENE Tax Group Liability

Under regulations issued by the U.S. Treasury Department, each corporation that joins in the filing of a consolidated federal income tax return for all or part of a taxable year, is severally liable for the entire tax liability in respect of the income (for the entire taxable year) of all the corporations whose income is required to be included in such return. By reason of this rule, Prisma, PGE, and CrossCountry (and certain of their subsidiaries) may be liable for unpaid federal income taxes (and interest and penalties thereon) of the ENE Tax Group for applicable periods. Similar liability may also arise for state and local income under analogous statutory or regulatory rules. However, ENE believes that it will fully satisfy all liability for income taxes of the ENE Tax Group (and comparable state and/or local groups) for all relevant periods.

Subject to certain limitations, however, ENE has agreed to indemnify CrossCountry for any taxes, and liabilities incurred in connection with such taxes, imposed on any Pipeline Group Company by reason of such Pipeline Group Company being severally liable for any taxes of any member of the ENE Tax Group pursuant to Treasury Regulation Section 1.1502-6(a) or any analogous state, local, or foreign law. It is expected that ENE will similarly indemnify PGE for any such liability for taxes sustained by PGE by reason of PGE having previously been a member of the ENE Tax Group. ENE may also provide a similar indemnity to Prisma, but, at this time, no decision has been made in this regard.

E. Risks Common to Reorganized Debtors, Operating Entities and Litigation Trusts

The following risks are applicable to two or more of the Reorganized Debtors, PGE, CrossCountry, Prisma, the Litigation Trust, and/or the Special Litigation Trust.

1. Changes in the Regulatory Environment

The Operating Entities are, depending on where their operations are located, subject to numerous domestic and international regulations and regulatory agencies including, but not limited to FERC, NRC, EPA, OPUC, SEC, DOT, and others. Changes in the regulatory environment have a direct impact on the Operating Entities' operations and may materially impact the Operating Entities' profitability. Refer to Sections IX.A.6., "Regulatory Environment", IX.A.3., "Competition" and VIII.A.3., "Regulatory Matters" for further information.

2. PUHCA

ENE is a holding company under PUHCA that is exempt from all the provisions thereunder, except Section 9(a)(2), which is applicable to the acquisition of affiliate interests in public utility companies. ENE is a holding company under PUHCA because it owns all the common stock of PGE. ENE's PUHCA exemption was obtained by the filing of applications for exemption with the SEC under Sections 3(a)(1), 3(a)(3), and 3(a)(5) of PUHCA. An applicant is exempt upon the filing of an application in good faith until the SEC grants or denies the application. By order dated October 7, 2002, the SEC scheduled a hearing on the applications. After a hearing held on December 5, 2002, SEC Chief Administrative Law Judge Brenda Murray issued an initial decision denying the applications on February 6, 2003. ENE and certain other participants in the proceeding petitioned the SEC to review the decision of the Administrative Law Judge and, on June 11, 2003, the SEC granted the petition. The briefing schedule for the SEC review was completed on September 3, 2003. Judge Murray's decision denying the exemptions is stayed pending the resolution of the SEC's further review. Oral argument before the SEC has been scheduled for December 4, 2003.

After the oral argument, the SEC may grant or deny one or more of the exemption applications. If the SEC finds that ENE does not qualify as an exempt holding company under PUHCA, ENE would be required to register under PUHCA. PUHCA imposes a number of restrictions on the operations of a registered holding company and its subsidiaries, including SEC approval of acquisitions of interests in utility and non-utility businesses, and transactions between companies in the holding company system. Certain affiliate arrangements for transition services, licensing and consolidated tax filings involving the Operating Entities, and other ENE subsidiaries, may be subject to SEC review and in some cases may not be authorized or may have to be modified. PUHCA also may restrict the ability of ENE and its subsidiaries, including the Operating Entities, to borrow money and finance new or existing businesses, to issue dividends out of capital or unearned surplus, and to reorganize businesses. In addition, if ENE must register as a holding company, the SEC could assert jurisdiction under PUHCA to review the corporate structure of ENE and its subsidiaries, voting power distribution, and the nature of the businesses in the registered holding company system. The SEC may require the simplification of the corporate structure through the divestiture of certain ENE subsidiaries, or otherwise, in a manner that may not be consistent with the Plan. SEC authorization also may be required to distribute the PGE Common Stock under the Plan. If ENE is required to register under PUHCA, such registration could lead to a delay in Plan implementation and, possibly, substantive revisions to the Plan. Indeed, the SEC staff has taken the position that, if ENE is required to register, the SEC's consent to the Plan, the Disclosure Statement, and the solicitation of votes on the Plan would be necessary prior to confirmation. The Debtors dispute this contention and do not believe that such consent is required. There can be no assurance that the Debtors will prevail on this issue. In any event, if ENE is required to register, the SEC may seek to assert jurisdiction under PUHCA over certain transactions contemplated under the Plan such as those described above.

The Debtors are currently simplifying the complex corporate structure of Prisma to, among other things, qualify Prisma's businesses as exempt foreign utility companies (FUCOs) under PUHCA. It is contemplated that FUCO status would exempt most transactions relating to these foreign projects, such as dividends, reorganizations, financings, and investments, from regulation under PUHCA if ENE ultimately is required to register as a holding company. Some of the companies related to the Debtors' foreign projects, however, may not qualify for FUCO status and will require special relief under PUHCA, for example, to continue to finance certain foreign operations (or to alter the terms of existing financings). The Debtors would apply for authorizations necessary to continue ongoing business operations and to implement the Plan, although there can be no assurance that such authorizations would be granted.

3. Environmental Laws and Regulations Affecting Operations

Controlling environmental laws and regulations generally require the Reorganized Debtors, their domestic non-Debtor subsidiaries and the Operating Entities to obtain and comply with a wide variety of environmental registrations, licenses, permits, inspections, and approvals. Environmental laws and regulations can also require the Reorganized Debtors, their domestic non-Debtor subsidiaries and the Operating Entities to perform environmental remediations under appropriate circumstances. There is no assurance that existing environmental laws or regulations will not be revised or that new laws or regulations seeking to protect the environment will not be adopted or become applicable to the Reorganized Debtors, their domestic non-Debtor subsidiaries and the Operating Entities or that the Reorganized Debtors, their domestic non-Debtor subsidiaries and the Operating Entities will not identify in the future conditions that will result in obligations or liabilities under existing environmental laws and regulations. Revised or additional laws or regulations that result in increased compliance costs or additional operating restrictions, or currently unanticipated costs or restrictions under existing laws or regulations, could have a material adverse effect on the Operating Entities' results of operations. Refer to Sections IX.A.7., "Environmental Regulation", X.A.3., "Transferred Businesses" and XI.A.7., "Investment Powers" for further information.

4. Competition

Many of the businesses owned by the Operating Entities currently face competition in their respective markets. For example, PGE faces competition from electricity service suppliers, energy brokers, independent power producers, and power marketers as a result of the restructuring of the Oregon electric industry. The pipeline businesses to be owned by CrossCountry and to be owned by Prisma face competition from other pipeline companies in their respective transportation services markets. For example, Transwestern faces competition resulting from the recent expansion of Kern River's pipeline and from a proposed expansion of El Paso Natural Gas's system. In addition, Florida Gas faces competition from Gulfstream's proposed expansion on the east coast of Florida. If existing competitors expand their capacities or new competitors enter the markets, competition will intensify. Furthermore, the availability and cost of the type of fuel used or transported by many of the businesses owned by the Operating Entities affect the competitive position of those businesses. For example, the availability and cost of coal affect the competitive position of PGE's coal-fired generating plants, the availability and cost of natural gas affect the competitive position of the Pipeline Businesses, and the availability and cost of fuel oil affect the competitive position of Florida Gas and of many of the electrical power plants to be owned by Prisma. If another type of fuel becomes more available or economically attractive than the type of fuel used or transported by a business, that business will face greater competition. Increased competition may result in a loss of market share and could have a material adverse effect on the Operating Entities' businesses, results of operations, and financial conditions or on the net sales proceeds received by the Reorganized Debtors in a sale of any of the Operating Entities.

5. Operational Hazards

The Operating Entities are subject to the inherent risks associated with the operation of complex utility companies, such as operational hazards and unforeseen interruptions caused by events beyond the Operating Entities' control. These events include, but are not limited to: (a) adverse weather conditions; (b) accidents and damage caused by third parties; (c) the breakdown or failure of equipment or processes; (d) the performance of the facilities below expected levels of capacity and efficiency; (e) release of toxic substances; and (f) catastrophic events such as explosions, fires, earthquakes, hurricanes, lightning, floods, landslides, or other similar events beyond the Operating Entities and Reorganized Debtors' control.

6. Lack of Trading Market; Restrictions on Underwriters

At the time of, or after, the distribution of Prisma Common Stock, CrossCountry Common Stock, PGE Common Stock, the Litigation Trust Interests, and the Special Litigation Trust Interests to the creditors, the conditions of which are described in the Plan, the Prisma Common Stock, CrossCountry Common Stock and PGE Common Stock may not, and the Litigation Trust Interests, and Special Litigation Trust Interests will not, satisfy the requirements to be listed on a national securities exchange or a NASDAQ market which include, among other things, registration under the appropriate provision of Section 12 of the Exchange Act and market value requirements. If the Prisma Common Stock, CrossCountry Common Stock, and PGE Common Stock satisfy such requirements, the respective issuers may list such securities, but (except with regard to CrossCountry, which has certain requirements to seek a listing under its CrossCountry Contribution and Separation Agreement, refer to Section IX.F.1.a., "CrossCountry Contribution and Separation Agreement" for further information) such issuers are under no obligation to do so and there can be no assurances that such listing will be made. Instead, the Prisma Common Stock, CrossCountry Common Stock, PGE Common Stock, the Litigation Trust Interests, and Special Litigation Trust Interests may trade in the over-the-counter market (commonly referred to as the "pink sheets"), but there can be no assurance that an active trading market will develop. Accordingly, no assurance can be given that a holder of Prisma Common Stock, CrossCountry Common Stock, PGE Common Stock, the Litigation Trust Interests, and Special Litigation Trust Interests will be able to sell such securities in the future or as to the price at which any sale may occur. If a trading market does exist, the Prisma Common Stock, CrossCountry Common Stock, PGE Common Stock, the Litigation Trust Interests, and Special Litigation Trust Interests could trade at prices higher or lower than the value ascribed to such securities herein depending upon many factors, including the prevailing interest rates, markets for similar securities, general economic and industry conditions, and the performance of, and investor expectations for, the issuer thereof.

As stated in Section XIII., "Securities Laws Matters", legislative history of section 1145 of the Bankruptcy Code provides a recipient of at least 10% of the voting securities of an issuer under a chapter 11 plan will be presumed to be a statutory underwriter within the meaning of section 1145(b)(i) of the Bankruptcy Code, and as a result the shares received by such recipient would not be made freely transferable by section 1145. The Debtors have assumed that no holder of Allowed Claims would receive 10% or more of any type of Plan Securities, but there can be no assurance of such result.

7. Lack of Reported Information

While PGE is currently obligated to file annual, quarterly, or periodic financial reports with the SEC pursuant to Sections 13 or 15(d) of the Exchange Act on Forms 10-Q and 10-K or 8-K, CrossCountry, Prisma, the Litigation Trust, and the Special Litigation Trust are not required to make, and have not made, such filings. Absent another requirement, none of CrossCountry, Prisma, the Litigation Trust, nor the Special Litigation Trust will be required to make such filings until it registers its Plan Securities, Litigation Trust Interest, or Special Litigation Trust Interests (if they are "equity securities" under the Exchange Act), as the case may be, under Section 12 of the Exchange Act, which CrossCountry is obligated to do pursuant to the CrossCountry Contribution and Separation Agreement. Refer to Section IX.F.1.a., "CrossCountry Contribution and Separation Agreement" for further information. While Prisma, the Litigation Trust, and the Special Litigation Trust may make such registration earlier, none will be required to make such registration until its equity securities are held by 500 or more holders of record and it has at least $10 million in assets, both at the end of its fiscal year.

Registration of the Plan Securities under Section 12 of the Exchange Act will require historical financial information audited by an independent auditor and covering a period as long as three fiscal years. While the Debtors intend that each of CrossCountry, PGE and Prisma will have such financial information prepared on a timely basis, there can be no assurance as to the timing of the availability of such audited financials or that the form of such financials will be acceptable to the SEC or the auditors of such Operating Entity. For example, if either the SEC or such Operating Entity's auditors require, as a related matter, that ENE's or certain of its subsidiaries' financial information be audited, the preparation of such audited financials may be materially delayed, as audited financial information of ENE and certain of its subsidiaries cannot be obtained. As another example, an Operating Entity may be unable to retain an auditor that does not have its independence compromised by a prior relationship with a Debtor. If an audit of such unavailable information is required, or a suitable independent auditor is not available or otherwise able to perform audit services on a timely basis, distribution of PGE Common Stock, CrossCountry Common Stock or Prisma Common Stock, as applicable, may be delayed until (i) the assets of the applicable issuer have been separated from ENE and such subsidiaries for a sufficient amount of time so that the required financial statements can be prepared and audited without an audit of such unavailable information or (ii) a suitable independent auditor is able to perform audit services.

8. Lack of Independent Operating History

While PGE does have an independent operating history, Prisma and CrossCountry do not have independent operating histories. Most of the personnel responsible for managing and operating the transferred businesses prior to the formation of Prisma and CrossCountry, and the current personnel of PGE, are expected to continue to be responsible for managing and operating such businesses going forward. However, Prisma and CrossCountry resources and, in many cases, bargaining power will be limited relative to the resources and bargaining power of ENE prior to its filing for bankruptcy. Accordingly, Prisma and CrossCountry may enter into agreements with lenders, partners, and other counterparties on terms that are less favorable than those that ENE was able to negotiate prior to filing for bankruptcy.

9. Negative Publicity

Adverse publicity and news coverage relating to the Enron Companies prior to the Initial Petition Date may negatively impact PGE, CrossCountry, and Prisma's business operations and relations with partners, regulators, lenders, and other third parties. The Reorganized Debtors' liquidation efforts may be similarly negatively impacted.

10. FERC

On June 25, 2003, FERC issued certain orders relating to the Enron Companies' activities in the Western U.S. energy market. Refer to Section XIV.G.1.d., "Litigation, Regulatory Proceedings and Investigations" for further information.

11. Credit Risks

For a variety of reasons, each of the Reorganized Debtors and Operating Entities is subject to credit risk with respect to accounts receivables or other amounts due them. For example, certain of the Reorganized Debtors and, to a lesser degree, PGE have a material portion of their accounts receivable due from entities presently in bankruptcy proceedings and there can be no assurance that other entities from whom monies are due will not petition for bankruptcy protection. In some cases, creditors of the Reorganized Debtors have asserted that the Debtors' prepetition activities provide them with a defense to paying all or a portion of an amount due to a Debtor. CrossCountry's interstate pipeline subsidiaries are required to accept the credit risk of all shippers posting amounts of collateral specified by the FERC on its existing pipelines. Prisma is subject to the credit risk of its contract counterparties; this risk may increase in certain circumstances where Prisma's contract provides for payment indexed to U.S. dollars and the contract counterparties' revenues are in currencies other than U.S. dollars. Hedging activities undertaken by PGE and CrossCountry, among others, may be rendered ineffective due to credit defaults of the hedge counterparty. No assurance can be given that these credit risks will not adversely affect the value of one or more of the Reorganized Debtors or Operating Entities.

12. Intercompany Claims and Causes of Action

Under the global compromise embodied in the Plan, the Debtors have generally waived inter-Debtor remedies, such as the potential disallowance, subordination, or recharacterization of Intercompany Claims, as well as certain affirmative claims or causes of action against other Debtors. However, these waivers do not affect the Debtors' ability to pursue third parties, and non-Debtor affiliates, on any claims, causes of action or challenges available to any of the Debtors. To the extent that the Debtors or Reorganized Debtors elect to pursue any claims, causes of action or challenges available against any of the Operating Entities or their subsidiaries and prevail, then the applicable Operating Entity may be adversely effected.

13. Taxes

There are a number of material income tax considerations, risks, and uncertainties associated with the consummation of the Plan. Refer to Section XV., "Certain Material Federal Income Tax Consequences of the Plan" and to Sections XIV.D.2., "ENE Tax Group Liability", XIV.I.4., "Tax Risks", XIV.H.3., "Tax Risks", XIV.G.1., "Economic, Political, Regulatory and Legal Risks" and Appendix J: "CrossCountry Financial Projections – 2003-2006" for additional information relating to tax risks.

14. Transportadora de Gas del Sur. S.A. TGS holds an exclusive 35-year license to operate Argentina's main natural gas pipeline. TGS's controlling shareholder is Compañía de Inversiones de Energía S.A., a joint venture by ENE and Petrobras Energía S.A. that holds approximately 70% of TGS's common stock. The license to operate the TGS pipeline imposes certain restrictions on the ability of certain ENE affiliates to undergo a change of control, which may be triggered by a distribution of more than 49% of the stock of CrossCountry. Transwestern has also guaranteed the performance of certain obligations of an ENE affiliate under shareholder and other agreements with its joint venture partner. The surviving performance obligations under these agreements primarily involve corporate governance issues and shareholder rights. ENE has provided certain indemnification rights to the CrossCountry Indemnified Parties in respect of such guaranty. Refer to Section IX.F., "Certain Relationships and Related Transactions" for further information. ENE anticipates seeking releases from the foregoing obligations and requirements under the license and the guaranty. However, there can be no assurance that such releases will be obtained, and if they are not obtained, that material liabilities would not be incurred by the ENE estate.

F. Reorganized Debtors Risks

In addition to the risk factors enumerated above, the Reorganized Debtors are subject to the following risks:

1. FERC Market Pricing Investigation

On February 12, 2002, FERC began a fact-finding investigation of potential manipulation of short-term electric and natural gas prices in the western United States. An adverse decision by FERC could result in the repricing of certain trading contracts and may have an adverse effect on the value of ENE's electric and natural gas trading contracts in the western United States, including the accounts receivable associated with such contracts.

2. FERC Investigation Regarding Qualifying Facility Status

FERC has filed two separate proceedings regarding five qualifying facilities in which ENE has or had an indirect ownership interest. The allegation is that ENE's ownership interest in and/or agreements with these qualifying facilities caused electric utility ownership in these projects to increase above the amount permitted to maintain qualifying facility status. In addition, on July 8, 2003, FERC trial staff filed a motion to join into the two above-mentioned proceedings, 17 additional challenges to qualifying facility status (known as dockets), one for each of 14 additional qualifying facilities in which ENE has or has had an indirect ownership interest, and 3 qualifying facilities with which ENE affiliates have had certain contractual relationships. An adverse decision by FERC could negatively affect the relevant Enron Company's equity interests in and/or contractual relationships with these qualifying facilities. Refer to Section IV.C., "Litigation and Government Investigations" for further information.

3. Greater than Budgeted Liquidation Costs

Winding down the Debtors' estates is a very complicated process and will require extensive resources. Prolonged governmental investigations, litigation, complex legal issues, complicated sale processes, changes in market conditions, and additional costs associated with the liquidation of assets that are not transferred to the Operating Entities may result in greater than expected costs. The Debtors have incurred significant costs to date for personnel and professional services. Due to the uncertainty as to the effort, cost, and time necessary to wind down the Debtors' estates, the future expenditures may be materially different than anticipated and may impact the ultimate value of the estates.

G. PGE Risks

In addition to the risk factors enumerated above, PGE is subject to the following risks:

1. Economic, Political, Regulatory and Legal Risks

a. Payment of Dividends. Historically PGE paid quarterly cash dividends to ENE. During the first two quarters of 2001, PGE paid an aggregate of $40 million in cash dividends to ENE. PGE has not paid any cash dividends to ENE since June 2001. However, in July 2002, PGE made a $27 million non-cash dividend to ENE. Pursuant to OPUC Order No. 97-196, dated June 4, 1997, which approved PGE's sale to ENE, ENE and PGE agreed to certain restrictions on PGE's ability to pay dividends to ENE. These restrictions include (i) not paying common stock dividends in an amount that would reduce the common stock equity capital portion of PGE's total capital to less than 48% without OPUC's approval and (ii) notifying OPUC either 30 days or 60 days in advance of certain dividends. As of March 31, 2003, PGE's common equity ratio was 52%. In connection with PGE's current 364-day credit facility due May 27, 2004, PGE agreed that it would not declare or pay any common stock dividends until the facility is terminated. In addition, under PGE's mortgage bonds, so long as any bonds of any series are outstanding, PGE may not declare or pay dividends (other than dividends in capital stock of PGE) on common stock of PGE or purchase or otherwise retire for a consideration (other than in exchange for or from the proceeds of other shares of capital stock of PGE) any shares of capital stock of PGE of any class, if the aggregate amount so expended after December 31, 1944 would exceed the aggregate amount of PGE's net income available for dividends on its common stock accumulated after December 31, 1944. At December 31, 2002 approximately $838 million of accumulated net income was available for payment of dividends under this provision.

There can be no assurance that PGE will be permitted under these or other contractual or regulatory restrictions to pay dividends to its common stockholders in the future.

b. Condemnation. In August 2002, the City Council of Portland, Oregon authorized expenditures for professional advice regarding potential acquisition of PGE, including acquiring PGE's assets by condemnation. In addition, initiative petitions circulated in Multnomah County obtained sufficient signatures to place a measure on an election ballot that, if passed, could result in the formation of a PUD in Multnomah County. In June 2003, the Multnomah County Board of Commissioners determined the boundaries of a proposed PUD and set a PUD formation initiative on the November 4, 2003 ballot to be voted on by the county voters. The initiative failed. In August 2003, initiative petitions circulated in Yamhill County also obtained sufficient signatures to place a measure on an election ballot. The Yamhill County Commissioners determined the boundaries of the proposed PUD and set March 2, 2004 as the date for voting on the formation initiative. The expressed intent of the PUD supporters is to have additional elections to expand the PUD boundaries to include all of PGE's service territory. If a PUD is formed, it would have the authority to condemn PGE's distribution assets within the boundaries of the district. Oregon law prohibits a PUD from condemning thermal generation plants. It is uncertain under Oregon law whether a PUD would be able to condemn PGE's hydro generation plants. At this time, PGE cannot assess the potential impact such condemnation would have on PGE. The mortgage indenture requires PGE to deposit the proceeds of any condemnation with the mortgage indenture trustee where they may be applied to redeem first mortgage bonds at PGE's option. There can be no assurance in such event that the proceeds will be sufficient to pay principal and or interest on the bonds or that any amount would be available for distribution to shareholders.

c. Membership in ENE's Consolidated Tax Group. PGE was a member of the ENE Tax Group from July 2, 1997 through May 7, 2001, and from December 24, 2002 through present. On December 31, 2002, in connection with being re-consolidated with the ENE Tax Group, PGE entered into a tax sharing agreement with ENE pursuant to which PGE agreed to make payments to ENE for income taxes that PGE would incur if it were not a member of the ENE Tax Group. Because PGE is treated as included in the ENE Tax Group, PGE does not pay income taxes to the IRS but, instead, it makes payments to ENE pursuant to the tax sharing agreement. As of July 31, 2003, PGE had paid $37 million to ENE under the tax sharing agreement for estimated taxes for the period from January 1 through March 31, 2003. The determination of whether PGE did, in fact, become a member of the ENE Tax Group on December 24, 2002 is fact intensive, and there can be no assurance that the IRS will agree with ENE's assessment. If the IRS does not agree that PGE became a member of the ENE Tax Group on December 24, 2002, and the matter is not resolved by the Bankruptcy Court or otherwise, PGE may be required to pay additional amounts to the IRS (and, possibly, to certain state and/or local taxing authorities as well). However, ENE believes that all of the requirements for PGE's re-consolidation with the ENE Tax Group have been satisfied.

d. Litigation, Regulatory Proceedings and Investigations. Current and future litigation, regulatory proceedings, and governmental audits and investigations could, individually or in the aggregate, have a material and adverse impact on PGE.

2. Operational Risks

a. Fluctuations in Wholesale Power Costs. PGE's owned generation capacity is not sufficient to meet its retail load requirements. To supplement its own generation, PGE purchases power through both long-term power purchase contracts and short-term, including spot, purchases in the wholesale market as needed. The availability and price of power PGE purchases is significantly affected by the amount of surplus generating capability in the western United States, the number and credit quality of wholesale marketers and brokers participating in the energy trading markets, the cost of fuels, price caps set by FERC, and hydro conditions. Northwest hydro conditions, such as a severe or sustained drought, have a significant impact on the supply and cost of power in the region, and on PGE's ability to economically displace its more expensive thermal generation. The availability and price of purchased power are also affected by weather conditions in the Northwest during winter months and in California and the Southwest during summer months. Although there are regulatory procedures for PGE to seek recovery of any additional power costs through its rates, there can be no assurance that PGE would be allowed such recovery.

b. Fuel Costs and Related Hedging Activities. PGE's primary business is to provide electricity to its retail customers. PGE uses both long-and short-term purchased power contracts to supplement its thermal and hydroelectric generation to meet its load, as well as to respond to seasonal fluctuations in the demand for electricity and variability in generating plant operations. In meeting these needs, PGE is exposed to market risk arising from the need to purchase power and to purchase fuel for its natural gas and coal-fired generating units. To lower its financial exposure related to commodity price fluctuations and manage its portfolio of resources, PGE routinely enters into contracts to hedge purchase and sale commitments, fuel requirements, weather conditions, inventories of natural gas, coal, and other commodities. As part of its strategy, PGE routinely utilizes fixed-price forward physical purchase and sales contracts, financial swaps, options, and futures contracts. As a result of marketplace illiquidity and other factors, PGE's power operations may, at times, be unable to fully hedge the portfolio for market risks. PGE may, at times, have an open position in the market, within established guidelines, resulting from the management of its portfolio. To the extent open positions exist, fluctuating commodity prices can impact financial results and financial position, either favorably or unfavorably. In addition, the risk management procedures PGE has in place may not always work as planned.

In connection with its hedging activities, PGE manages the risk of counterparty default by performing financial credit reviews and setting limits and monitoring exposures, requiring collateral when needed and using standardized enabling agreements that allow for the netting of positive and negative exposures associated with a counterparty. Despite such mitigation efforts, defaults by counterparties may periodically occur.

Even though PGE attempts to hedge some portion of its fuel requirements, PGE still may face the risk of supply interruptions and fuel price volatility. The price PGE can obtain for the sale of energy may not compensate it for its increased fuel costs, which may have an adverse effect on financial performance.

As a result of these and other factors, PGE cannot predict with precision the impact that its risk management decisions may have on its business, operating results, or financial position.

c. Decrease in Electricity Demand. A sustained decrease in demand for electricity in PGE's service territory would significantly reduce revenues and, as a result, adversely impact the financial condition of PGE. Factors that could lead to a decrease in demand include, among others, a recession or other adverse economic condition in the territory, particularly any economic slowdown in the manufacturing and technology sectors, and weather conditions that result in lower consumption by consumers.

3. Environmental Risks

a. Portland Harbor. A 1997 investigation of a portion of the Willamette River known as the Portland Harbor, conducted by the EPA, revealed significant contamination of sediments within the harbor. Subsequently, the EPA included Portland Harbor on the federal National Priority list pursuant to CERCLA. PGE, together with a large number of other parties, received notice from the EPA of PGE's potential liability with respect to the Portland Harbor contamination. PGE's investigations to date have shown no significant soil or groundwater contaminations with a pathway to the Willamette River sediments from its Harborton substation facility. It is believed that PGE's contribution to the sediment contamination, if any, could qualify it as a de minimis potential responsible party under CERCLA. There can be no assurance, however, that PGE will not incur significant liability with respect to the cost of investigation and remediation of the Portland Harbor, which may materially adversely impact PGE's financial condition or results of operations. Refer to Section VIII.A.7., "Environmental Matters" for further information.

H. CrossCountry

In addition to the risk factors enumerated above, CrossCountry is subject to the following risks:

1. Economic, Political, Regulatory and Legal Risks

a. Execution of Growth Strategy. CrossCountry's current strategy contemplates growth through both the acquisition of other energy assets and the expansion of the Pipeline Businesses' existing systems. Any limitations on the access of CrossCountry or its subsidiaries and affiliates to debt or equity capital may impair CrossCountry's ability to execute its growth strategy. CrossCountry's ability to access reasonably priced debt capital is dependent in part on its ability, and the ability of its subsidiaries, to maintain favorable credit ratings. On November 6, 2003, Transwestern closed on a 364-day extension and restructuring of its prior credit facility. The aggregate commitment under the extended and restructured facility is $486 million, composed of a $50 million revolver and $436 million of 364 day term loans.

In addition, there are numerous risks involved in CrossCountry's growth strategy through acquisitions, including, among others, that CrossCountry may: (i) not be able to identify suitable acquisition candidates; (ii) not be able to make acquisitions on economically acceptable terms, or if made, assure that the acquisitions will be successful; (iii) encounter material costs in seeking to make acquisitions or not be able to complete any potential acquisitions it has pursued; (iv) encounter difficulties in integrating operations and systems following acquisitions; or (v) encounter difficulties or delays in obtaining regulatory approvals, which, in each case, could have an adverse impact on CrossCountry's financial condition.

The failure of CrossCountry or the Pipeline Businesses to generate sufficient funds in the future from the Pipeline Businesses' operations or other financing sources may also cause the delay or abandonment of the Pipeline Businesses' expansion plans and thus, adversely impact CrossCountry's earnings and financial condition. Also a proposed expansion may cost more than planned to complete, and such excess costs, if found imprudent by FERC, may not be recoverable. The inability to recover any such costs or expenditures may adversely impact CrossCountry's financial condition. Transwestern's planned San Juan expansion is dependent on Transwestern's ability to secure additional financing to cover the capital cost of that project.

In addition, the Pipeline Businesses' ability to engage in any expansion project will be subject to numerous factors beyond CrossCountry's control, including, among others, the following: (i) customers may be unwilling to sign long-term contracts for service that would make use of a planned expansion; (ii) CrossCountry's competitors may provide transportation services to the area to which CrossCountry is expanding; (iii) competing entities may construct new competing pipelines, and those new or expanded pipelines may offer transportation services that are more desirable to customers because of costs, location, supply options, facilities, or other factors; and (iv) the necessity of obtaining shareholder approvals may delay or interfere with completion of acquisitions or expansions in certain cases, including the approval of ENE prior to the distribution to Creditors of CrossCountry Common Stock pursuant to the Plan.

There can be no assurance that any future expansion or extension project will be undertaken or, if undertaken, will be successful.

b. FERC Proceedings Regarding Financing and Cash Management Practices. CrossCountry's interstate Pipeline Businesses are subject to extensive regulation by FERC. A FERC proceeding is currently underway that relates to certain past financing and cash management activities of Transwestern. That proceeding questioned Transwestern's entering into a $550 million loan prior to ENE's bankruptcy and its loan of the proceeds of that borrowing to ENE. The proceeding resulted in a settlement between FERC's staff and Transwestern but the settlement was challenged by a Transwestern customer and is now awaiting final action by FERC. If accepted by FERC, the protesting customer's position could result in disallowance of Transwestern's ability to recover costs associated with the loan. Proceedings are also ongoing with respect to industry-wide cash management practices and intracompany transactions, as well as FERC audits of such practices, among ENE-affiliated pipelines. CrossCountry does not expect any of these proceedings to have a material adverse impact on its financial position but no assurance can be given as to their final outcome. Refer to Section IX.A.6., "Regulatory Environment" for further information.

c. FERC Imposed Tariff Adjustments. Because CrossCountry's businesses are primarily interstate natural gas pipelines subject to regulation as natural gas companies under the Natural Gas Act of 1938, as amended, the rates the interstate Pipeline Businesses can charge their customers and other terms and conditions of service are subject to approval by FERC.

Under the terms of the interstate Pipeline Businesses' transportation service contracts and in accordance with FERC's rate-making principles, the interstate Pipeline Businesses' current maximum tariff rates are designed to recover costs included in their pipeline systems' regulatory cost of service that are associated with the construction and operation of the pipeline systems that are reasonably and prudently incurred, including a reasonable return on invested capital. CrossCountry's interstate Pipeline Businesses' tariffs also permit them to charge negotiated rates for transportation services to certain shippers, subject to the availability of base tariff rates, or recourse rates, calculated on a traditional cost-of-service basis and provided that non-rate terms and conditions in any agreement do not deviate in any material aspect from those set forth in the tariff or applicable form of service agreement contained in the tariff.

No assurance can be given that FERC will not alter or refine its preferred methodology for establishing pipeline rates and tariff structures. Nor can any assurance be given that all costs incurred, including a reasonable return on capital, will be recoverable through rates. Failure by the interstate Pipeline Businesses to recover material costs would adversely impact CrossCountry's financial condition. Additionally, other aspects of the interstate Pipeline Businesses' rate and services structures, such as the mechanism for recovery of compressor fuel from customers, may be modified by FERC during rate review proceedings and such modification of rate and service structures may have an adverse impact on CrossCountry's financial condition. Specifically, Transwestern's current authorization to collect physical volumes of natural gas from its customers to compensate Transwestern for natural gas burned as fuel in its compressors could be modified in a way that reduces the amount of natural gas Transwestern has available to sell for its own account.

In addition, regulators and shippers on the pipelines have rights to challenge the rates the pipelines charge and the pipelines' tariffs may be modified in periodic rate proceedings, or at any time in response to a complaint proceeding initiated by a customer of the pipeline, or by FERC itself. While there are currently no material proceedings challenging the rates of any of the interstate Pipeline Businesses, CrossCountry cannot predict what challenges the interstate Pipeline Businesses may have to their rates in the future.

Florida Gas filed a new rate case on October 1, 2003 and Northern Border Pipeline, and Transwestern are required under previous settlement agreements with FERC to file new rate cases to be effective no later than May 2006 and November 2006, respectively. While CrossCountry does not expect those rate proceedings to adversely impact its financial position, no assurance can be given as to the final outcome.

d. Maintenance and Expiration of Transportation Service Agreements. CrossCountry's financial condition and results of operations are dependent on the interstate Pipeline Businesses' ability to maintain long-term transportation service agreements with their largest customers at favorable transportation rates. Upon expiration, existing customers may not extend their contracts at rates favorable to the interstate Pipeline Businesses on a long-term basis, or at all. The interstate Pipeline Businesses may also be unable to obtain favorable replacement agreements as existing contracts expire. The extension or replacement of the existing contracts with their customers depends on a number of factors beyond the interstate Pipeline Businesses' control, including but not limited to: (i) availability of economically deliverable supplies of natural gas for transport through their pipeline systems; (ii) demand for natural gas in the interstate Pipeline Businesses' market areas; (iii) the relative price of natural gas compared to competing fuels; (iv) the basis differential between receipt and delivery points on the pipeline systems; (v) competition to deliver natural gas to the interstate Pipeline Businesses' major marketplaces from alternative sources; (vi) whether transportation of natural gas pursuant to contracts continues to be market practice; and (vii) whether the interstate Pipeline Businesses' strategies, including their expansion strategies, continue to be successful.

Transwestern, Florida Gas and Northern Border Pipeline also have significant amounts of their capacity subject to contracts that expire over the next four years. Additionally, certain of Florida Gas's contracts are subject to early termination in the event of deregulation of the Florida electric market or upon the occurrence of other triggering events. Any failure to extend or replace these contracts may have an adverse impact on CrossCountry's financial condition.

In addition, competition from other interstate natural gas pipelines may adversely impact the ability of the interstate Pipeline Businesses to re-contract for expiring transportation capacity and could lead to lower levels of profitability. Transwestern faces competition resulting from the recent expansion of Kern River's pipeline and from a proposed expansion of El Paso Natural Gas's system. In addition, Florida Gas faces competition from Gulfstream's proposed expansion on the East coast of Florida.

e. Concentrated Gas Transportation Revenues. Certain of CrossCountry's Pipeline Businesses are dependent on a relatively small number of customers for a significant portion of their revenues. As a result, failure of one or more of the Pipeline Businesses' most significant customers to pay for contracted pipeline capacity reservation charges, for reasons related to financial distress or otherwise, could reduce CrossCountry's revenues materially if alternate arrangements were not made, such as adequate replacement contracts. Accordingly, the loss of one of these customers or a decline in its creditworthiness could adversely impact the results of operations, financial condition, and cash-flow of CrossCountry and its Pipeline Businesses.

f. Expansion of Northern Border Partners' Midstream Gas Gathering Business. Northern Border Partners' ability to expand its midstream gas gathering business will depend in large part on the pace of drilling and production activity in the Powder River, Wind River, and Williston Basins or other natural gas producing basins in which it subsequently constructs or acquires gas gathering and processing operations. Drilling and production activity will be impacted by a number of factors beyond Northern Border Partners' control, including demand for and prices of natural gas, producer response to the recently issued Record of Decision for the Wyoming Environmental Impact Statement and outcome of pending lawsuits challenging the Record of Decision, the ability of producers to obtain necessary permits, and capacity constraints on natural gas transmission pipelines that transport gas from the producing areas.

g. Operating Income from the Purchase and Sale of Natural Gas and Natural Gas Liquids. Certain of CrossCountry's subsidiaries or affiliates derive a portion of their operating income from the purchase and sale of natural gas and NGLs. Citrus Trading derives substantially all of its operating margin from the purchase and sale of natural gas, and marks-to-market its portfolio of contracts, the longest of which extends to 2013. Under Transwestern's tariff, Transwestern's customers provide Transwestern with more natural gas than is necessary to fuel Transwestern's pipeline system's compressors. The amount of surplus fuel is dependent on system throughput in each of Transwestern's pipeline segments. This surplus gas is available for Transwestern to resell to third parties for Transwestern's own account. Additionally, a Northern Border Partners affiliate, Bear Paw Energy, has gathering and processing contracts associated with its midstream gas gathering business in the Williston Basin that require its customers to pay for the service they receive from Bear Paw Energy with physical quantities of natural gas and liquids. The amount of natural gas and NGLS received is dependent on total system throughput and the composition of the untreated gas stream.

Citrus Trading is naturally hedged on approximately half of its portfolio due to purchases and sales being on substantially the same terms, with the remainder of the portfolio purchased on a floating price basis and sold at a fixed price. In addition, Transwestern and Northern Border Partners' midstream gathering business in the Williston Basin have contracted to hedge the value of their assets and operations, and are substantially hedged through 2003 and 2004. However, these businesses do not cover the entire exposure of their assets or their positions to market price volatility and the coverage will vary over time. To the extent these businesses have unhedged positions or their hedging procedures are not as successful as planned, fluctuating commodity prices may adversely impact CrossCountry's financial condition. Refer to Section XIV.H.4.a., "Citrus Trading Contract Risk".

h. Continued Access to Tribal Lands. The Pipeline Businesses' ability to operate their pipelines on certain tribal lands will depend on their success in maintaining existing rights-of-way and obtaining new rights-of-way on those tribal lands. Transwestern recently extended the term of its right-of-way grant with several tribes including the Navajo Nation. The extended right-of-way grant with the Navajo Nation expires in 2009. Additionally, securing rights-of-way is critical to Transwestern's ability to construct its proposed San Juan expansion project and other expansion projects. CrossCountry cannot assure that it will be able to acquire new rights-of-way on tribal lands or maintain access to existing rights-of-way upon the expiration of current grants. Accordingly, CrossCountry's financial position could be adversely affected if the costs of new or extended right-of-way grants are not allowed to be recovered in the Pipeline Businesses' rates.

i. Significant Decrease in Demand for Natural Gas. A sustained decrease in demand for natural gas in the markets served by the Pipeline Businesses' systems would significantly reduce the revenues of the Pipeline Businesses and, consequently, adversely impact the financial condition of CrossCountry. Factors that could lead to a decrease in market demand include, among others, the following: (a) a recession or other adverse economic condition that results in lower spending by consumers on natural gas; (b) an increase in the market price of natural gas; (c) higher fuel taxes or other governmental or regulatory actions that increase, directly or indirectly, the cost of natural gas or that limit the use of natural gas; or (d) a shift by consumers to more fuel-efficient or alternative fuel machinery or an improvement in fuel economy, whether as a result of technological advances by manufacturers, pending legislation proposing to mandate higher fuel economy, or otherwise.

j. Litigation, Regulatory Proceedings and Investigations. Current and future litigation, regulatory proceedings, and governmental audits and investigations including claims relating to prepetition activities of ENE, could, individually or in the aggregate, have a material adverse impact on CrossCountry. For a description of current litigation, regulatory proceedings and governmental investigations that involve or may involve CrossCountry and its subsidiaries and affiliates, refer to Sections IX.A.6., "Regulatory Environment" and IX.C., Historical Financials, Projections and Valuation".

k. Related Party Transactions

The discussion of the results of operations for Citrus Corp. and Subsidiaries contained in Appendix I includes a discussion of an $80 million gas sales, purchase and exchange arrangement and a $20 million prepayment arrangement, each between Citrus Trading and an ENE affiliate during December 2000 and January 2001. Although the proceeds from the $80 million transactions were reported in the audited financial statements of Citrus as cash from operating activities, these gas sales arrangements could be viewed as financings. These transactions are currently under review. Refer to Appendix I: "CrossCountry Historical Financials" for further information.

l. Retiree Benefits. In accordance with the Debtors' request to terminate the Enron Gas Pipelines Retiree Benefits Trust, the Debtors intend to distribute certain trust assets to CrossCountry entities following such entities' express assumption of retiree benefit liabilities associated with such assets for current and former employees. The applicable CrossCountry entities will be assuming liabilities estimated as of June 30, 2002 of approximately $16.87 million and will be receiving assets estimated as of the same date of approximately $7.55 million. The CrossCountry entities are permitted to recover a portion of the cost of retiree benefits through their rate cases, however, there can be no assurance that the CrossCountry entities will be able to recover the full cost of their retiree benefit liabilities. Refer to Section IV.A.8.c, "Retiree Benefits" for further information.

2. Structural Risks

a. Dependence on Earnings and Distributions of Citrus and Northern Border Partners. CrossCountry will derive a significant portion of its cash flow from its interest in Citrus and its general and limited partner interests in Northern Border Partners. A significant decline in Northern Border Partners' or Citrus's earnings and/or cash distributions would have a corresponding negative impact on CrossCountry. For further information on the earnings and cash distributions of Northern Border Partners, refer to Section IX.A.2.c., "Northern Plains" or Northern Border Partners' 2002 Annual Report on Form 10-K available for free in the "Related Documents" section at http://www.enron.com/corp/por/.

b. Control over Pipeline Businesses. Prior to the distribution of CrossCountry's common stock pursuant to the Plan, ENE's consent will be required for CrossCountry to take certain corporate actions. These actions include, among others, entering into certain joint ventures, mergers or other business combinations, undertaking certain capital expenditures or expansions, or incurring certain indebtedness. Refer to Section IX.F.1.a., "CrossCountry Contribution and Separation Agreement" for further information.

CrossCountry will have varying degrees of management control over the operation of its Pipeline Businesses that are not wholly owned subsidiaries. With respect to these entities, certain significant actions will require the consent of other joint venture parties or equity holders or their representatives, and CrossCountry will not be in a position to direct the outcome of all matters related to the underlying businesses. For example, Citrus's organizational documents and Florida Gas's organizational documents require that "important matters" be approved by both shareholders of Citrus. Important matters include the declaration of dividends and similar payments, the approval of operating budgets, the incurrence of indebtedness, and the consummation of a number of significant transactions. There is a risk that Citrus, with 50/50 joint ownership between CrossCountry and Southern Natural Gas, will reach a deadlock in the decision-making process, which could adversely affect the operation of this business, possibly for an extended period. Refer to Section IX.A.1.b., "Employees and Pipeline Services" for further information. The Citrus governance documents do not provide a specific mechanism for resolving such a deadlock. Accordingly, any disagreement that arises between the owners of Citrus could prevent approval of actions requiring an affirmative vote of the Citrus Board of Directors or require litigation to resolve.

Likewise, certain decisions by Northern Border Partners and its subsidiary Northern Border Pipeline require concurrence by entities not controlled by CrossCountry. Accordingly, significant expansions and acquisitions, as well as any change to the distribution policy at Northern Border Pipeline, would require consent by entities not controlled by CrossCountry. CrossCountry may be unable to unilaterally compel outcomes that are in CrossCountry's best interest as to those non-controlled subsidiaries.

3. Tax Risks

The CrossCountry Projections assume that ENE will pay cash for the full amount of the net receivable balance owing to Transwestern under the applicable tax allocation agreement; however, because this net receivable balance may be subject to adjustments (as a result of audits by taxing authorities) and future negotiations between ENE and Transwestern, and because any payment with respect to such balance is subject to prior consent of the Creditors' Committee, the actual amount that ultimately is paid (if any) may vary materially from the amount projected. Refer to Appendix J: "CrossCountry Financial Projections – 2003-2006".

4. Other Risks

a. Citrus Trading Contract Risk. Citrus Trading is a party to a long term commodity sale contract with Auburndale Power Partners that is substantially "out-of-the-money." This "out-of-the-money" position was historically offset by gas supply arrangements, one of which was recently terminated. That termination leaves the Auburndale contract 50% unhedged. Citrus Trading's "out-of-the-money" position with Auburndale is no longer fully offset by in the money supply contracts. Citrus Trading is currently performing under the Auburndale contract, but there can be no assurance that it will be able to continue performing or continue as a going concern.

I. Prisma Risks

In addition to the risk factors enumerated above, Prisma is subject to the following risks:

1. Economic, Political, Regulatory, and Legal Risks

a. International Economic Slowdown. The current worldwide economic slowdown has increased political and regulatory pressure to lower energy costs in many countries in which Prisma operates. The delivery of energy products and services is an inherently political business because it ultimately involves the delivery of a basic necessity to a large group of consumers. When economies are growing, governments tend to focus on the development of energy infrastructure projects. When economies slow, political pressures shift to emphasize the lowering of energy costs. Economic downturns have also historically led to governments coming into power that are interested in playing a more active role in regulating energy prices. The regulatory systems in many of the countries in which the transferred businesses conduct operations are not immune from, and at times are highly susceptible to, such political pressures. Political pressure may cause regulators in the countries in which the transferred businesses conduct operations to enact new regulations or to modify or repeal existing regulations that could adversely affect the transferred businesses. There can also be no assurances that political pressures will not result in the expropriation of assets or businesses by the countries in which the transferred businesses operate.

b. Regulatory Intervention and Political Pressure. Past and potential regulatory intervention and political pressures may lead to tariffs that are not compensatory or otherwise undermine the value of the long-term contracts entered into by the transferred businesses. The revenues of some of the key businesses expected to be a part of Prisma, including SK-Enron, Elektro, and Vengas, are dependent on tariffs or other regulatory structures that allow regulatory authorities to periodically review the prices such businesses charge customers and the other terms and conditions under which services and products are offered. Other key businesses expected to be a part of Prisma, such as Accroven, Cuiabá, and Trakya, rely on long-term contracts with governmental or quasi-governmental entities for all or substantially all of their revenues. Because of political or other pressures, including those discussed above, regulatory authorities may set rates that do not provide a meaningful rate of return on amounts invested or allow for a sufficient recovery of operating costs or may otherwise not respect the contractual frameworks upon which some of the transferred business were developed and are currently operated. For example, Elektro's concession agreement provides that its terms can be changed by the government in certain cases to re-establish "financial and economic equilibrium." However, neither the standards nor the mechanics for this process are clearly specified and any such change could be effected in a manner adverse to Elektro's interest. In addition, in Brazil, certain government-appointed officials have questioned certain contractually fixed terms of the Cuiabá project's power sales agreement with a government-controlled entity. In 2001 and 2002 in Turkey, a New Energy Market Law and related regulations were adopted and a new regulatory body created to liberalize the electricity market. The new law and regulations do not exempt existing generators from its requirements and the new regulator has been confrontational with the Trakya project, expressing its intention to abrogate or renegotiate existing contracts in favor of the new regulatory regime. The abrogation or renegotiation of any of the long-term contracts of a business would likely lead to significantly lower revenues for such business.

c. Political Instability, Civil Unrest, and Regime Change. Prisma may suffer losses as a result of political instability, civil unrest, and regime change. The political and social conditions in many of the countries where the transferred businesses are located present many risks, such as civil strife, guerrilla activities, insurrection, border disputes, leadership succession turmoil, war, expropriation, and nationalization, that are generally greater than risks in the United States. For example, the revelations of nuclear weapons capabilities in North Korea have increased regional tensions and harmed the investment environment in South Korea and may harm the financial results of SK-Enron. Also, general strikes in Venezuela in late 2002 left Vengas with a drastically reduced supply of LPG for almost a month and caused PdVSA to be delinquent in payments to Accroven. Continuing political turmoil in Venezuela and in other countries may continue to harm the financial results of the transferred businesses.

Changes in governments, even through democratic elections, have caused, and may in the future cause, losses for some of the transferred businesses as a result of the uncertainty they create. Changes in governments in foreign countries frequently result in greater regulatory changes than do changes in administrations in the United States.

d. Devaluations of Foreign Currencies. Prisma may suffer losses as a result of devaluations in the currencies of the countries in which it is expected to operate. The revenues of some of the key businesses expected to be a part of Prisma, including SK-Enron, Elektro, and Vengas, are collected substantially or exclusively in the relevant local currency. In such cases, a strengthening of the U.S. dollar relative to such local currency will reduce the amount of cash flow and net income of such business in U.S. dollar terms. Such devaluations will also diminish the asset base in U.S. dollar terms on which businesses subject to rate of return tariff regulation, such as SK-Enron and Elektro, are allowed to earn a regulated return. Certain countries where Prisma will derive significant revenue and be exposed to these risks, including Brazil and Venezuela, have experienced moderate to severe devaluations of the local currency in recent years. The results of Elektro and Vengas have been materially reduced in U.S. dollar terms as a result and will continue to be reduced to the extent the relevant local currency continues to decline in value relative to the U.S. dollar.

Currency devaluation risk is further exacerbated when a business has borrowed funds or has significant payment obligations in one type of currency but receives revenue in another. This is the case with Elektro, which has dollar-denominated loans and dollar-denominated payment obligations under a long-term PPA. In such cases, an adverse change in exchange rates will erode the capital of such business and reduce its ability to meet debt service or other payment obligations or to obtain dollar-denominated goods and services.

In some cases the contractual agreements that are the sources of revenue of the transferred businesses provide for payments to be made in, or indexed to, U.S. dollars or a currency freely convertible into U.S. dollars. No assurance can be given, however, that these structures will continue to be effective in all cases or that any given counterparty will be able to obtain acceptable currency to meet its obligations or that these structures will not adversely affect the credit risk of any given counterparty. Other than these contractual arrangements, it is not anticipated that Prisma will be able to hedge against devaluation risks in a cost-effective matter.

e. Inability to Remit or Convert Profits. Prisma may not receive dividends or other distributions from the transferred businesses because of exchange controls or similar government regulations restricting currency conversion or repatriation of profits. Economic and monetary policies and conditions in a given country and other factors could affect Prisma or its businesses' ability to convert local currency into U.S. dollars or to remit funds out of the foreign country. Furthermore, the central banks of most foreign countries have the ability to suspend, restrict or otherwise impose conditions on foreign exchange transactions or to approve the remittance of currency into or out of the country. In several of the countries where Prisma is expected to operate, such controls and restrictions have historically been imposed and in others are currently being imposed. For example, Brazil imposed remittance restrictions for six months from late 1989 to early 1990, and Venezuela adopted a currency exchange regime in February 2003 that has yet to be fully implemented, but requires that all exchanges be made through the central bank at a set rate. As with devaluation risk discussed above, these risks can be mitigated only to a limited extent through contractual arrangements. Refer to Section X.A.3.c(iii), "Vengas, S.A. (Vengas)" for further information on the currency exchange regime in place in Venezuela.

f. Difficulty Enforcing and Defending Contractual and Legal Rights. Certain countries in which Prisma is expected to operate do not have well-developed legal or judicial systems and lack a well-developed, consolidated body of laws governing infrastructure businesses and foreign investment enterprises. In many jurisdictions in which Prisma is expected to operate, there is little if any precedent relating to the structures for such businesses. In addition, the administration of laws and regulations by government agencies in such countries may be subject to considerable discretion. As a result, Prisma and the businesses expected to be a part of Prisma may be unable to enforce their rights under material agreements and governmental rules and regulations.

While most of the transferred businesses have entered into agreements that require dispute resolution by international arbitration, such provisions may be difficult to enforce and may not provide the anticipated benefits, and awards resulting from such arbitration may be difficult or impossible to collect. Parties to agreements may try to use local courts to stay or otherwise frustrate arbitration proceedings. For example, despite contractual clauses requiring international arbitration, ENE's 50% partner in SK-Enron recently petitioned a local court and was successful in obtaining the court's permission to place a "preliminary attachment" lien, which was ultimately not enforced, on ENE's ownership interest in the business in an effort to obtain an advantage in resolving a shareholder disagreement.

Any awards obtained in arbitration are often difficult to enforce, both because of procedural difficulties and because it is often difficult to find assets that can be levied against in jurisdictions where such an award will be enforced by local courts. In addition, many of the transferred businesses' contracts have counterparties that are sovereigns or other governmental entities, the assets of which are sometimes deemed to be immune from execution. International arbitration or litigation in foreign countries can be a very costly and lengthy process. Even if a transferred business receives an arbitral award or judgment in its favor, it may be unable to collect on such award or judgment to recoup its losses.

g. **Litigation, Regulatory Proceedings, and Investigations**. Current and future litigation, regulatory proceedings, and governmental audits and investigations could, individually or in the aggregate, have a material and adverse impact on Prisma. For a description of current litigation, regulatory proceedings and governmental investigations that involve or may involve Prisma and its subsidiaries and affiliates, refer to Sections IX.A.6., "Regulatory Environment" and X.C., "Legal Proceedings" for further information.

2. Operational Risks

a. **Uninsured Plant and Equipment Failures**. The power generation businesses that are expected to be a part of Prisma use complex technologies in their operations. A number of these businesses may experience plant and equipment failures that last for extended periods of time. For example, excessive vibration at the Trakya power plant led to an unscheduled outage lasting 92 days beginning in January 2002 and the catastrophic failure of a combustion turbine at the Cuiabá power plant led to a partial unscheduled outage lasting 204 days beginning in August 2001. While it is expected that Prisma will maintain insurance to cover most equipment failures, it will not be able to cover every potential risk and loss. In addition, the deductible waiting period under business interruption policies requires a set period of days to pass prior to receiving benefits from the policies. Prisma may suffer material losses if an equipment failure occurs that is incapable of repair or remedy for an extended period of time, or if that equipment or failure is uninsurable.

b. **Difficulties Obtaining Insurance**. Prisma may not be able to obtain all customary, desirable, or required insurance on reasonable terms or at all. The market for insurance has changed dramatically in recent years, as a result of the events of September 11, 2001, recent political upheavals, the rise of terrorism, and the armed conflicts in Afghanistan and Iraq. Costs for many types of insurance, such as terrorism insurance, business interruption insurance, and other disaster-based coverage, have risen significantly. Many of the businesses expected to be a part of Prisma have seen their insurance premiums and deductible amounts increase dramatically since 2001. In the future, Prisma may have to spend even greater amounts for insurance premiums, possibly for less coverage. In some cases, such insurance may not be available on commercially reasonable terms for certain businesses, which could have an adverse effect on Prisma's financial condition in the event of an uninsured casualty. Further, many of Prisma's project financings require specific levels of certain insurance. A failure to obtain the required insurance has put, and could in the future put additional, financings in default.

c. **Concentration of Customers and Suppliers**. Certain of the transferred businesses rely upon one or a limited number of customers that provide all or substantially all of the business's revenue and/or a limited number of suppliers to provide LPG, natural gas, liquid fuel of various types, and other services required for the operation of the business. Prisma's customers, in turn, are also dependent on transmission and delivery systems to deliver the product to the end-users. The failure of these systems may make Prisma's customers less willing or able to make required payments to Prisma.

In certain cases there are long-term purchase or supply agreements and the financial performance of a particular business is dependent upon the continued performance by a customer or supplier of its obligations under such long-term agreement. As a result of the failure of a major customer or supplier to meet its contractual obligations, the affected business may be in default under loan or other agreements, and such business may be unable to meet current debt service obligations or operating expenses and financial results could be materially adversely affected. Any such circumstance that became chronic or prolonged could result in the loss of all economic value from such business for Prisma.

In a number of cases, a transferred business's sole supplier or customer is a government-owned entity. In such cases contractual dealings can be more difficult and could become politicized. The government-owned entity may act in accordance with political objectives and not on commercially reasonable terms. For example, the government-owned entity may use its position to force the renegotiation of long-term purchase or supply agreements when market forces cause the underlying economics of an agreement to no longer favor the government-owned entity. Such renegotiation would result in a loss of value from such contracts for the transferred business.

3. Structural Risks

a. Inability to Control Transferred Businesses. Prisma will own interests in and manage its businesses exclusively through subsidiaries. Prisma will have varying degrees of management control over the operation of its businesses because Prisma's ownership may vary anywhere from 100% to significantly less than 50%. Refer to the ownership charts in X.A.3., "Transferred Businesses" for further information about each business segment. In some joint venture subsidiaries, Prisma is able to exert a significant degree of influence with respect to the management and operation of the business through contractual agreements granting operating authority to Prisma or its wholly owned subsidiaries, the right through shareholder or other governance agreements to appoint the officers of the joint venture and the right to fill positions on boards of directors or management committees. In certain other joint venture subsidiaries, Prisma's ability to exert influence is more limited. Even in subsidiaries where Prisma has significant rights, actions with respect to many significant matters require the consent of other joint venture parties or equity holders or their representatives and Prisma is not in a position to direct the outcome of many matters related to the underlying businesses. Where Prisma can nominate or appoint officers or directors of a given legal entity, such persons may owe a fiduciary duty to all stakeholders of such entity and will not be able to act solely in the interest and at the direction of Prisma. To the extent the interests of such entity, its other shareholders or its lenders are inconsistent with those of Prisma, the actions of such officers and directors in fulfilling their fiduciary duties may adversely affect the value of Prisma's equity interests in the entity.

Although Prisma will seek to establish centralized internal controls and procedures, including standards of internal accounting control, for each business in which it owns an interest, because of its limited control over certain businesses, these efforts may not always be successful. Prisma may not be able to ensure that internal accounting controls are adequate in businesses that it does not control. In addition, varying business cultures and practices in the 14 countries in which Prisma expects to own interests may make it difficult to implement and monitor adequate internal controls regardless of Prisma's ownership in or control over any business.

There is a danger that transferred businesses with divided ownership, such as SK-Enron and the 50/50 joint venture between Prisma and Shell with respect to Cuiabá, will reach a deadlock in the decision-making process, which could adversely affect the operation of those businesses, possibly for an extended period. The resolution of such a deadlock in some of Prisma's businesses requires the operation of buy-sell procedures, which allow one owner to set a price at which the other owner is required either to sell its interest or buy the other owner's interest. In any such case, there is a risk that such a deadlock could arise at a time when Prisma does not have sufficient funds available to buy out another partner and therefore would be required to sell its interest even if it believed that the price specified was not representative of the value of the interest Prisma held. In addition, any such forced transfer could have significant negative tax or accounting implications for Prisma.

b. Reliance on Subsidiaries for Dividends and Distributions. Substantially all of Prisma's cash flow will be dependent upon the receipt of cash dividends and distributions or other transfers from its subsidiaries. Prisma's subsidiaries will be separate and distinct legal entities that in certain instances have no obligation, contingent or otherwise, to make any funds available to Prisma, whether by dividends, loans or other payments. For example, SK-Enron has historically reinvested its earnings and not paid dividends pursuant to the terms of a shareholders agreement that obligates the parties to minimize dividends. In addition, Cuiabá uses a substantial portion of all available earnings to pay loans to ENHBV, an ENE affiliate that may not be transferred to Prisma. Accroven has not been able to pay dividends because it has not achieved project completion (as defined in its financing documents). Prisma will be unable to unilaterally cause dividends or distributions to be made from many of the transferred businesses in which it owns less than a 100% interest. In addition, each subsidiary's ability to pay dividends to Prisma depends on any statutory or contractual restrictions that may be applicable to such subsidiary, which may include requirements to maintain minimum levels of working capital and other assets. Included in such contractual restrictions are the debt agreements of certain subsidiaries that restrict their ability to pay dividends, make distributions, or otherwise transfer funds to Prisma. In addition, a substantial amount of the assets of certain of Prisma's subsidiaries have been pledged as collateral under such debt agreements. To the extent Prisma's subsidiaries do not have funds available or are otherwise restricted from paying dividends to Prisma, its ability to pay dividends on its common stock will be adversely affected. Dividend policies may also be impacted by withholding taxes and other tax treatment that may make it disadvantageous to pay dividends.

c. Transfer Restrictions. Most of the transferred businesses are subject to transfer restrictions running in favor of co-sponsors, financing parties, governmental agencies issuing required approvals, off-takers, and others. While Prisma is expected to own and operate or otherwise participate in the management of all of the businesses initially contributed to Prisma, should it desire to sell any in the future, it may need to obtain a consent or waiver of any such restrictions applicable to the business to be sold. The existence of such transfer restrictions may make it more difficult for Prisma to sell its interests and may adversely affect the price at which it may be able to sell its interests.

d. Concentration of Revenues. Prisma's results will be disproportionately affected by the results of a few of its largest businesses. It is estimated that SK-Enron and Elektro will represent a material portion of Prisma's revenues, which leaves it disproportionably vulnerable to any negative developments that may arise with respect to those businesses or in South Korea or Brazil.

4. Tax Risks

a. Tax Treaties. Prisma's ability to repatriate the maximum amount of earnings from the various foreign jurisdictions in which its projects conduct activities may be affected by whether income tax treaty benefits are available. The Cayman Islands does not have an income tax treaty network with other countries.

b. Passive Foreign Investment Company. For U.S. federal income tax purposes, Prisma is a "foreign corporation." A foreign corporation is classified as a PFIC for federal income tax purposes in any taxable year in which, after taking into account its pro-rata share of the gross income and assets of any company, U.S. or foreign, in which such foreign corporation is considered to own 25% or more of the shares by value, either (i) 75% or more of its gross income in the taxable year is passive income, or (ii) 50% or more of its assets (averaged over the year and ordinarily determined based on fair market value) are held for the production of, or produce, passive income.

The Debtors do not anticipate that Prisma will be a PFIC for its first taxable year and, based on Prisma's current business plan, do not anticipate that Prisma will become a PFIC. However, because the Debtors' expectations are based, in part, on interpretations of existing law as to which there is no specific guidance, and because the tests for PFIC status are applied annually, there can be no assurance that Prisma will not be treated as a PFIC. If Prisma is, or becomes, a PFIC, certain shareholders thereof may be subject to adverse U.S. federal income tax consequences upon receipt of distributions from Prisma or upon realizing a gain on the disposition of shares of Prisma Common Stock, including taxation of such amounts as ordinary income (which does not qualify for the reduced 15% tax rate applicable to certain "qualified dividend income") and the imposition of an interest charge on the resulting tax liability as if such ordinary income accrued over such shareholders' holding period for the Prisma Common Stock.

Holders of Claims who may receive Prisma Common Stock under the Plan are urged to consult their own tax advisers regarding income derived from holding or disposing of Prisma Common Stock.

c. Tax Determinations. The businesses to be transferred to Prisma have taken tax positions on many issues and with respect to each of the various jurisdictions in which they may be subject to taxation. Although such transferred businesses believe that such positions are correct, no assurance can be given that taxing authorities will not take a contrary view on any of a number of issues that could have a material adverse effect on the results of Prisma.

d. Differences in Valuation. Upon the transfer of assets (most of which are contracts rights and as such are considered intangibles for U.S. tax purposes) to Prisma, U.S. gain is likely to be recognized in the amount of the difference between the fair market value of the contract rights and the tax basis in either the stock or assets transferred. There is a risk of valuation controversy with the IRS. However, in view of the amount of the Debtors' NOL, the Debtors believe that no material amount of federal income tax liability could result from such controversy. For a discussion of the Debtors' NOL, refer to Section XV., "Certain Material Federal Income Tax Consequences of the Plan".

5. Other Risks

a. Contractual and Regulatory Disputes. Certain of Prisma's subsidiaries are currently involved in material disputes with regulatory authorities, partners, or contractual counterparties and have taken tax positions that may be subject to dispute. The outcome of these disputes could have a material adverse impact on Prisma's financial condition and on the operation of Prisma's business. Refer to Sections X.A.3., "Transferred Businesses" and X.C., "Legal Proceedings" for further information on such disputes.

b. Third-Party Consent to Transfer of Businesses. At the current time, no operating businesses or assets have been transferred to Prisma. Various approvals and consents of third parties (including governmental authorities) will be needed before the businesses described in this Disclosure Statement can be transferred to Prisma as contemplated by the Plan. There can be no assurance that all or any of such approvals or consents can be obtained. Refer to Section X.A.2., "Risk Factors" for additional information regarding consents required. If any required approval or consent cannot be obtained, then at the discretion of ENE, subject to the consent of the Creditors' Committee as contemplated in the Plan, such business will not be transferred to the ownership of Prisma and, instead, will remain, directly or indirectly, with ENE. Refer to Section VII.C.1., "Categories of Remaining Assets" for further information. As a result, it is possible that Prisma's businesses may not include all of the transferred businesses described in this Disclosure Statement. In addition, it is possible that any consents or approvals that are given could contain conditions or limitations that could adversely affect Prisma's ability to operate and manage its business, or adversely affect its financial results.

Some business may be transferred to Prisma without obtaining certain third party consents that such third parties assert are required to effect such transfer. Transfers without such consents may result in litigation that could have substantial financial consequences to Prisma.

c. Investment Company Act of 1940. The Investment Company Act requires the registration of, and imposes various substantive restrictions on, certain companies that engage primarily, or propose to engage primarily, in the business of investing, reinvesting or trading in securities, or that fail certain tests regarding the composition of assets and sources of income and are not primarily engaged in businesses other than investing, holding, owning, or trading securities. Based on a preliminary analysis, which assumed that all of the businesses to be transferred to Prisma as described in this Disclosure Statement are in fact transferred, Prisma believes that it will not be required to register as an "investment company" under the Investment Company Act. There can be no assurance, however, that (i) a change in the mix of businesses to be transferred to Prisma or any subsequent information will not change this analysis, or (ii) the SEC will not otherwise determine that Prisma is an "investment company" required to register under the Investment Company Act. If Prisma were required to register as an investment company under the Investment Company Act, it would become subject to substantial regulations with respect to its capital structure, management, operations, transactions with affiliates, and other matters. Registration as an investment company under the Investment Company Act would have a material adverse effect on Prisma.

J. Litigation Trust Risks

In addition to the risk factors enumerated above, the Litigation Trust and the Special Litigation Trust are subject to the following risk:

1. Nonoccurrence of Distributions

Distributions from the Litigation Trust and the Special Litigation Trust will be dependent upon the success of the Litigation Trust Claims and Special Litigation Trust Claims and the proceeds of such Litigation Trust Claims and Special Litigation Trust Claims being in excess of the liabilities, obligations, and expenses of the Litigation Trust and Special Litigation Trust, as the case may be. The Debtors can make no assurances that there will be any distributions from the Litigation Trust or the Special Litigation Trust.

XV. Certain Material Federal Income Tax Consequences of the Plan

Capitalized terms used throughout this Disclosure Statement are defined in Appendix A: "Material Defined Terms for Enron Disclosure Statement" attached hereto.

The following discussion summarizes certain material federal income tax consequences of the implementation of the Plan to the Debtors and to certain holders of Allowed Claims. This summary does not address the federal income tax consequences to holders of Claims who are deemed to have rejected the Plan in accordance with the provisions of section 1126(g) of the Bankruptcy Code (*i.e.*, holders of Enron Subordinated Debenture Claims (Class 183), Subordinated Claims (Classes 376-382), Enron Preferred Equity Interests (Class 383), Enron Common Equity Interest (Class 384), and Other Equity Interests (Class 385)) or holders whose Claims are entitled to payment in full in Cash or are otherwise unimpaired under the Plan and to holders of Claims who are deemed to have accepted the Plan (*i.e.*, holders of Allowed Administrative Expense Claims, Allowed Priority Claims and Allowed Secured Claims and Intercompany Claims). Additionally, this summary does not address the federal income tax consequences to holders of Allowed Intercompany Claims or to Settling Former Employees.

This summary is based on the IRC, existing and proposed Treasury Regulations, judicial decisions, and published administrative rules and pronouncements of the IRS as in effect on the date hereof, all of which are subject to change, possibly on a retroactive basis. Any such change could significantly affect the federal income tax consequences described below.

The federal income tax consequences of the Plan are complex and are subject to significant uncertainties. The Debtors have not requested an opinion of counsel with respect to any of the tax aspects of the Plan. While the Debtors have filed ruling requests with the IRS concerning certain, but not all, of the federal income tax consequences of the Plan, there is no assurance that a favorable ruling will be obtained, and the consummation of the Plan is not conditioned upon the issuance of such rulings.

This summary does not address state, local or foreign income or other tax consequences of the Plan, nor does it purport to address the federal income tax consequences of the Plan to special classes of taxpayers (such as non-U.S. persons, broker-dealers, banks, mutual funds, insurance companies, financial institutions, thrifts, small business investment companies, regulated investment companies, tax-exempt organizations, persons holding Common Stock of any of the Operating Entities as part of a hedging, straddle, conversion or constructive sale transaction or other integrated investments, traders in securities that elect to use a mark-to-market method of accounting for their security holding, certain expatriates, or former long term residents of the United States, persons who receive Common Stock of any of the Operating Entities as compensation, holders of 10% or more of the voting power (directly, indirectly or constructively) of Prisma, or pass-through entities or investors in pass-through entities).

ACCORDINGLY, THE FOLLOWING SUMMARY IS FOR INFORMATIONAL PURPOSES ONLY AND IS NOT A SUBSTITUTE FOR CAREFUL TAX PLANNING AND ADVICE BASED UPON THE PARTICULAR CIRCUMSTANCES PERTAINING TO A HOLDER OF A CLAIM. EACH HOLDER OF A CLAIM IS URGED TO CONSULT ITS OWN TAX ADVISORS FOR THE FEDERAL, STATE, LOCAL AND FOREIGN INCOME AND OTHER TAX CONSEQUENCES APPLICABLE TO IT UNDER THE PLAN.

A. Consequences to the Debtors

For federal income tax purposes, ENE is the parent of an affiliated group of corporations that includes certain of the Debtors and certain of their corporate subsidiaries that join in the filing of a consolidated federal income tax return. This group of corporations, the ENE Tax Group, has reported substantial consolidated NOL carryforwards for federal income tax purposes as of December 31, 2002. In addition, the Debtors expect that the ENE Tax Group will incur additional losses during the taxable year ending December 31, 2003, which the Debtors expect will generate additional NOL carryforwards for the ENE Tax Group as of December 31, 2003. The amount of such NOLs and NOL carryforwards remains subject to review and adjustment by the IRS and to the application of Sections 108 and 382 of the IRC.

If the Debtors remain in existence following the Effective Date, the sole purpose of their remaining in existence will be the winding-up of their affairs. Accordingly, the Debtors intend to treat the Plan as a plan of liquidation for federal income tax purposes. As discussed below, due to the lack of direct authoritative guidance as to the survival and utilization of NOL carryforwards and the timing of recognition of cancellation of indebtedness in the context of a plan of liquidation there is a risk that certain of the Debtors' favorable tax attributes (such as any losses incurred through the end of the taxable year in which the Plan becomes effective, NOL carryforwards, and tax basis) may be substantially reduced, eliminated, or subjected to significant limitations as the result of implementation of the Plan. The Debtors believe that, notwithstanding the potential for attribute reduction, elimination or limitation, implementation of the Plan should not cause them to incur a material amount of federal income tax so long as they have disposed of substantially all of their assets on or prior to the earlier of (a) the earliest date on which an "ownership change" (within the meaning of Section 382 of the IRC, as discussed below) occurs or (b) the last day of the taxable year that includes the earliest date on which they are treated, for federal income tax purposes, as having a discharge of a material amount of indebtedness (as discussed below). The Debtors' objective is to implement the Plan in a manner that will cause them to have disposed of substantially all of their assets on or prior to the earlier of these dates; however, there can be no assurance that the Debtors will achieve this objective because (i) there is a lack of direct authoritative guidance as to when these dates occur and (ii) certain of the Debtors' assets are subject to transfer restrictions (including the possible requirement for governmental or third-party private consents) that may prevent their timely disposition by the Debtors.

1. Cancellation of Debt

The IRC provides that a debtor in a bankruptcy case must reduce certain of its tax attributes – such as NOL carryforwards, current year NOLs, tax credits, and tax basis in assets – by the amount of any COD that arises by reason of the discharge of the debtor's indebtedness. Under recently issued Treasury Regulations (as well as proposed tax legislation) the reduction in certain tax attributes (such as NOL carryforwards) occurs on a consolidated basis where, as in the case of the Debtors who are members of the ENE Tax Group, a consolidated federal income tax return is filed. COD is the amount by which the adjusted issue price of indebtedness discharged exceeds the amount of cash, the issue price of any debt instrument and the fair market value of any other property given in exchange therefor, subject to certain statutory or judicial exceptions that can apply to limit the amount of COD (such as where the payment of the cancelled debt would have given rise to a tax deduction).

If the amount of such a debtor's COD is sufficiently large, it can eliminate these favorable tax attributes; to the extent the amount of COD exceeds the amount of such tax attributes, the excess COD has no adverse federal income tax consequence. Any reduction in tax attributes under these rules does not occur until the end of the taxable year after such attributes have been applied to determine the tax in the year of discharge or, in the case of asset basis reduction, the first day of the taxable year following the taxable year in which the COD occurs.

The Debtors believe that the implementation of the Plan should not cause them to incur a material amount of federal income tax by reason of COD so long as they have disposed of substantially all of their assets on or prior to the last day of the taxable year that includes the earliest date on which they are treated, for federal income tax purposes, as recognizing a material amount of COD. The Debtors' objective is to implement the Plan in a manner that will cause them to have disposed of substantially all of their assets on or prior to such date; however, there can be no assurance that the Debtors will achieve this objective because (i) there is a lack of direct authoritative guidance as to when such date occurs and (ii) certain of the Debtors' assets are subject to transfer restrictions (including the possible requirement for governmental or third-party private consents) that may prevent their timely disposition by the Debtors. The Debtors have filed a ruling request with the IRS regarding the applications of the COD rules to the

Debtors in the context of the Plan. However, there is no assurance that a favorable ruling will be obtained.

2. Limitations on NOL Carryforwards and Other Tax Attributes

a. Section 382 Limitations – General. Under Section 382 of the IRC, if a corporation (or consolidated group) undergoes an "ownership change," the amount of its pre-change losses (including NOL carryforwards from periods before the ownership change and certain losses or deductions which are "built-in," (*i.e.*, economically accrued but unrecognized), as of the date of the ownership change) that may be utilized to offset future taxable income generally is subject to an annual limitation.

Subject to the business continuation requirement discussed below, the amount of this Annual Limitation is equal to the product of (i) the fair market value of the stock of the corporation (or, in the case of a consolidated group, the common parent) immediately before the ownership change (with certain adjustments) multiplied by (ii) the "long-term tax-exempt rate," which is the highest of the adjusted federal long-term rates in effect for any month in the 3-calendar-month period ending with the calendar month in which the ownership change occurs. For a corporation (or consolidated group) in bankruptcy that undergoes the ownership change pursuant to a confirmed bankruptcy plan, the stock value generally is determined immediately after (rather than before) the ownership change by taking into account the surrender or cancellation of creditors' claims, also with certain adjustments. The Annual Limitation can potentially be increased by the amount of certain recognized built-in gains.

Notwithstanding the foregoing general rule, however, if the corporation (or the consolidated group) does not continue its historic business or use a significant portion of its historic assets in a new business for two years after the ownership change, the Annual Limitation resulting from the ownership change is zero (potentially increased by certain recognized built-in gains).

As indicated above, the Annual Limitation does not only limit the amount of NOL carryforward that can be utilized after an ownership change occurs, it can also operate to limit the deductibility of built-in losses recognized subsequent to the date of the ownership change. If a loss corporation (or consolidated group) has a net unrealized built-in loss at the time of an ownership change (taking into account most assets and items of "built-in" income and deduction), then any built-in losses recognized during the following five years (up to the amount of the original net unrealized built-in loss) generally will be treated as pre-change losses and similarly will be subject to the Annual Limitation. Conversely, if the loss corporation (or consolidated group) has a net unrealized built-in gain at the time of an ownership change, any built-in gains recognized during the following five years (up to the amount of the original net unrealized built-in gain) generally will increase the Annual Limitation in the year recognized, such that the loss corporation (or consolidated group) would be permitted to use its pre-change losses against such built-in gain income in addition to its regular annual allowance. Although the rule applicable to net unrealized built-in losses generally applies to consolidated groups on a consolidated basis, certain corporations that join the consolidated group within the preceding five years may not be able to be taken into account in the group computation of net unrealized built-in loss. Such corporations would nevertheless still be taken into account in determining whether the consolidated group has a net unrealized built-in gain. In general, a loss corporation's (or consolidated group's) net unrealized built-in gain or loss will be deemed to be zero unless it is greater than the lesser of (i) $10 million or (ii) 15% of the fair market value of its assets (with certain adjustments) before the ownership change.

b. Section 382 Limitations – Possible Application to the ENE Tax Group. In light of the foregoing, the ENE Tax Group's ability to utilize certain NOLs (and carryforwards thereof) and certain other tax attributes would be potentially subject to limitation if ENE were to undergo an "ownership change" within the meaning of Section 382 of the IRC by reason of the implementation of the Plan (or otherwise). Although there is a lack of direct authoritative guidance on this point, the Debtors intend to take the position that because the Plan is a plan of liquidation for federal income tax purposes, neither its confirmation nor consummation will cause the holders of Claims to be deemed to have acquired stock, or the shareholders to be deemed to have surrendered stock so that there will not have been an ownership change for purposes of Section 382 of the IRC. If, notwithstanding this position, an ownership change were to occur, the Debtors could incur a material amount of federal income tax in connection with the implementation of the Plan unless (1) the Debtors' assets are distributed pursuant to the Plan on or before the date of such ownership change or (2) the amount of the Annual Limitation (taking into account the increase therein for certain recognized built-in gains) is large enough to permit the ENE Tax Group to utilize an amount of NOL carryforwards (and other attributes) sufficient to offset such income tax.

The Debtors believe that the implementation of the Plan should not cause them to incur a material amount of federal income tax by reason of the application of Section 382 of the IRC so long as they have disposed of substantially all of their assets on or prior to the earliest date on which an "ownership change" (within the meaning of Section 382 of the IRC) occurs. The Debtors' objective is to implement the Plan in a manner that will cause them to have disposed of substantially all of their assets on or prior to such date; however, there can be no assurance that the Debtors will achieve this objective because (i) there is a lack of direct authoritative guidance as to when such date occurs and (ii) certain of the Debtors' assets are subject to transfer restrictions (including the possible requirement for governmental or third party private consents) that may prevent their timely disposition by the Debtors. The Debtors have filed a ruling request with the IRS regarding the applications of IRC Section 382 to the Debtors in the context of the Plan. However, there is no assurance that a favorable ruling will be obtained.

3. Alternative Minimum Tax

In general, a federal alternative minimum tax is imposed on a corporation's alternative minimum taxable income at a 20% tax rate to the extent such tax exceeds the corporation's regular federal income tax. For purposes of computing taxable income for alternative minimum tax purposes, certain tax deductions and other beneficial allowances are modified or eliminated. For example, a corporation is generally not allowed to offset more than 90% of its taxable income for federal alternative minimum tax purposes by available NOL carryforwards.

In addition, if a corporation (or consolidated group) undergoes an "ownership change" within the meaning of Section 382 of the IRC and is in a net unrealized built-in loss position (as determined for federal alternative minimum tax purposes) on the date of the ownership change, the corporation's (or consolidated group's) aggregate tax basis in its assets would be reduced for certain federal alternative minimum tax purposes to reflect the fair market value of such assets as of the change date.

Any federal alternative minimum tax that a corporation pays generally will be allowed as a nonrefundable credit against its regular federal income tax liability in future taxable years to the extent the corporation is no longer subject to federal alternative minimum tax.

Except as described below, the Debtors believe that the implementation of the Plan should not cause them to incur a material amount of federal alternative minimum tax so long as they have disposed of substantially all of their assets on or prior to the earlier of (a) the earliest date on which an "ownership change" (within the meaning of Section 382 of the IRC, as discussed below) occurs or (b) the last day of the taxable year that includes the earliest date on which they are treated, for federal income tax purposes, as having a discharge of a material amount of indebtedness (as discussed below). The Debtors' objective is to implement the Plan in a manner that will cause them to have disposed of substantially all of their assets on or prior to the earlier of these dates; however, there can be no assurance that the Debtors will achieve this objective because (i) there is a lack of direct authoritative guidance as to when these dates occur and (ii) certain of the Debtors' assets are subject to transfer restriction (including the possible requirement for governmental or third party private consents) that may prevent their timely disposition by the Debtors. Moreover, even if the Debtors accomplish the foregoing objectives, alternative minimum tax liability could be incurred if, pursuant to the Plan, the stock of PGE or CrossCountry (or a subsidiary of CrossCountry) is transferred in a manner that enables the company whose stock is transferred to increase its basis in its assets for federal income tax purposes; however, the Debtors do not anticipate that they would effect such a transaction unless it were determined to maximize the value of these assets taking into account the effect of any applicable alternative minimum tax.

B. Consequences to the Holders of Certain Claims

1. Consequences to Holders of Convenience Claims

Pursuant to the Plan, holders of Allowed Convenience Claims (in Classes 191 to 375) will receive Cash in satisfaction and discharge of their Claims. Refer to Section XV.B.2., "Consequences to Holders of General Unsecured Claims and Guaranty Claims" for information relevant to holders of Allowed Convenience Claims that elect to have such Claims treated as General Unsecured Claims.

In general, each holder of an Allowed Convenience Claim will recognize gain or loss in an amount equal to the difference between (i) the amount of Cash received by such holder in satisfaction of its Claim (other than any Claim for accrued but unpaid interest) and (ii) the holder's adjusted tax basis in its Claim (other than any Claim for accrued but unpaid interest). Refer to Section XV.B.3., "Distributions in Discharge of Accrued But Unpaid Interest" for a discussion of the tax consequences of any Claims for accrued interest.

Where gain or loss is recognized by a holder, the character of such gain or loss as long-term or short-term capital gain or loss or as ordinary income or loss will be determined by a number of factors, including the tax status of the holder, whether the Claim constitutes a capital asset in the hands of the holder and how long it has been held, whether the Claim was acquired at a market discount, and whether and to what extent the holder previously had claimed a bad debt deduction.

A holder that purchased its Claim from a prior holder at a market discount may be subject to the market discount rules of the IRC. Under those rules, assuming that the holder has made no election to amortize the market discount into income on a current basis with respect to any market discount instrument, any gain recognized on the exchange of such Claim (subject to a *de minimis* rule) generally would be characterized as ordinary income to the extent of the accrued market discount on such Claim as of the date of the exchange.

Each holder of an Allowed Convenience Claim should consult its own tax advisor to determine the character of any gain or loss recognized by it in connection with the implementation of the Plan.

2. Consequences to Holders of General Unsecured Claims and Guaranty Claims

a. Gain or Loss – Generally. In general, holders of Allowed General Unsecured Claims (Classes 3-182) and holders of Guaranty Claims (Classes 185-189) will recognize gain or loss in an amount equal to the difference between (i) such holder's "amount realized" in respect of its Claim, which is the amount of cash and the fair market value of any property (including, as discussed below, such holder's undivided interest in the assets transferred to the Operating Trusts (to the extent such trusts are established) and the Remaining Assets Trust (to the extent such trust is established), and in the case of a holder of Allowed General Unsecured Claim, also including such holder's undivided interest in the assets transferred to the Litigation Trust and the Special Litigation Trust, received by the holder in satisfaction of its Claim (other than amounts that are in respect of any Claim for accrued but unpaid interest, and amounts required to be treated as imputed interest (refer to Section XV.B.2.b., "Gain or Loss – Imputed Interest" and (ii) the holder's adjusted tax basis in its Claim (other than any Claim for accrued but unpaid interest). Refer to Section XV.B.3., "Distributions in Discharge of Accrued But Unpaid Interest" for a discussion of the federal income tax consequences of any Claim for accrued interest. Refer to Section XV.B., "Consequences to the Holders of Certain Claims" for information relevant to holders of Allowed General unsecured Claims and Allowed Guaranty Claims that elect to have such claims treated as Convenience Claims.

As discussed below, each of the Litigation Trust, the Special Litigation Trust, the Operating Trusts, and the Remaining Assets Trust has been structured with the intention of qualifying as a "grantor trust" for federal income tax purposes. Accordingly, the Debtors will treat each holder of an Allowed General Unsecured Claim or Allowed Guaranty Claim that receives an interest in one of the above-referenced trusts for federal income tax purposes as directly receiving, and as a direct owner of, its allocable percentage of the assets of the applicable trust. Refer to Section XV.B.4., "Tax Treatment of the Trusts and Holders of Beneficial Interests". Pursuant to the Plan, a good faith valuation of the assets of each trust as of the date of distribution of interests in such trust will be made, and the Debtors and the trustees of the trusts will use such valuations in filing any required reports or returns with the IRS. All holders of Allowed General Unsecured Claims and Allowed Guaranty Claims will be informed of such determination and are required by the Plan to use such valuations on tax returns and reports filed with the IRS.

Any amount that such a holder receives as a distribution from the Litigation Trust, the Special Litigation Trust, the Operating Trusts, and/or the Remaining Assets trust in respect of its beneficial interests in the trust (other than as a result of a subsequent distribution from the Disputed Claim Reserve) should not be included, for federal income tax purposes, in such holder's amount realized in respect of its Claim but should be separately treated as a distribution received in respect of such holder's beneficial (ownership) interests in the applicable trust. Refer to Section XV.B.4., "Tax Treatment of the Trusts and Holders of Beneficial Interests".

b. Gain or Loss – Imputed Interest. If distributions are made to a holder of an Allowed General Unsecured Claim or Allowed Guaranty Claim by the Debtors (and/or the Disputed Claims Reserve) subsequent to the Effective Date or on multiple dates, the imputed interest provisions of the IRC may apply to treat a portion of such distributions as interest for federal income tax purposes. Holders of such claims are urged to consult their tax advisors regarding the possible application of these imputed interest rules.

c. Gain or Loss – Effect of Potential Future Distributions. The possibility that a holder of an Allowed General Unsecured Claim or Allowed Guaranty Claim will receive distributions after the Effective Date can have tax consequences to such holders.

(i) All distributions (whether or not received on the Effective Date) to a holder of an Allowed General Unsecured Claim or Allowed Guaranty Claim (including distributions from the Disputed Claims Reserve (other than amounts attributable to earnings)) should be taxable to such holder in accordance with the principles discussed above in "Gain or Loss – Generally." As noted in "Gain or Loss – Imputed Interest" above, the imputed interest provisions of the IRC may apply to treat a portion of any subsequent distribution as imputed interest.

(ii) It is possible that recognition of any loss realized by a holder of an Allowed General Unsecured Claim or Allowed Guaranty Claim may be deferred until such holder can no longer receive future distributions under the Plan from the Disputed Claims Reserve and/or the Debtors.

(iii) It is possible that any gain realized by a holder of an Allowed General Unsecured Claim or Allowed Guaranty Claim in respect of distributions from the Debtors and/or the Disputed Claims Reserve may be deferred under the "installment method" of reporting. Such deferral of gain recognition may not be advantageous to a particular holder and, accordingly, holders of such claims should consider the desirability of making an election to forego the application of the installment method.

(iv) Holders of Allowed General Unsecured Claims and Allowed Guaranty Claims are urged to consult their tax advisors regarding the possibility for such

deferral of recognition of gains and losses and the possibility of electing out of the installment method of reporting any gain realized in respect of their Claims.

d. Gain or Loss – Character. Where gain or loss is recognized by a holder of an Allowed General Unsecured Claim or Allowed Guaranty Claim in respect of its Claim, the character of such gain or loss as long-term or short-term capital gain or loss or as ordinary income or loss will be determined by a number of factors, including the tax status of the holder, whether the Claim constitutes a capital asset in the hands of the holder and how long it has been held, whether the Claim was acquired at a market discount and whether and to what extent the holder had previously claimed a bad debt deduction. A holder of such a claim that purchased its Claim from a prior holder at a market discount may be subject to the market discount rules of the IRC. Under those rules, assuming that the holder has made no election to amortize the market discount into income on a current basis with respect to any market discount instrument, any gain recognized on the exchange of such Claim (subject to a *de minimis* rule) generally would be characterized as ordinary income to the extent of the accrued market discount on such Claim as of the date of the exchange. Holders of Allowed General Unsecured Claims and Allowed Guaranty Claims are urged to consult their tax advisors to determine the character of any gain or loss recognized in connection with the implementation of the Plan.

e. Property Received - Tax Basis. In general, a holder's tax basis in any property received (including the holder's undivided interest in the assets of the Litigation Trust, the Special Litigation Trust, the Operating Trusts, and/or the Remaining Assets Trust) will equal the fair market value of such property on the date of distribution, and the holding period for such property generally will begin the day following the date of distribution.

f. Gain or Loss - Certain Holders Whose Claims Constitute Stock or Securities. If (1) a holder's Claim constitutes either "stock" or a "security" for federal income tax purposes, (2) the obligor under the Claim (x) is treated as a corporation for federal income tax purposes and (y) is one of the entities that is treated, for federal income tax purposes, as transferring assets to Prisma or CrossCountry on or prior to the Effective Date, and (3) the assets so transferred by such corporation constitute "substantially all" of the assets of such corporation for federal income tax purposes, then such holder's federal income tax treatment may differ from the treatment described above. For such Holder, the formation of Prisma or CrossCountry may be treated as a tax-free reorganization for federal income tax purposes that would prevent such a holder from recognizing a loss in respect of the implementation of the Plan; such loss would instead be reflected in a higher than fair market value basis in the Prisma Common Stock and/or CrossCountry Common Stock received by such holder. For such a holder that would otherwise recognize a gain in respect of the implementation of the Plan, it is possible that tax-free reorganization treatment could defer a portion of such gain; such deferred gain would be reflected in a lower than fair market value basis in the Prisma Common Stock and/or CrossCountry Common Stock received by such holder. It is possible that this alternative tax treatment (and consequent deferral of loss recognition and possible deferral of gain recognition) could also apply to a holder of a Claim against ENE that constitutes either "stock" or a "security" for federal income tax purposes (even if the formation of CrossCountry did not cause such treatment, as discussed above), if ENE were to transfer the Existing PGE Common Stock or the PGE Common Stock to a holding company (which, subject to regulatory considerations, ENE has the right to do.)

Whether a Claim constitutes either "stock" or a "security" for federal income tax purposes depends on the facts and circumstances surrounding the origin and nature of the Claim. Prominent factors that courts have relied upon in determining whether an obligation or other instrument constitutes either "stock" or a "security" include: (a) the term of the instrument, (b) whether the instrument is secured, (c) the degree of subordination of the instrument, (d) the ratio of debt to equity of the issuer, (e) the riskiness of the issuer's business, and (f) the negotiability of the instrument. Holders of Allowed General Unsecured Claims and Allowed Guaranty Claims should consult their tax advisors to determine whether their Claims constitute either "stock" or "securities" for federal income tax purposes and whether this alternative federal income tax treatment may be applicable to them.

g. Assets owned by Operating Subsidiaries – Tax Basis. The Debtors believe that certain of the Operating Entities and certain of their subsidiaries have a tax basis in their respective assets that is substantially lower than the fair market value of such assets. The Debtors may seek to implement the Plan in a manner that would increase the tax basis of certain such assets to their respective fair market value. However, there is no assurance that the Debtors will be able to achieve this objective.

h. Prisma – Certain PFIC Considerations. Pursuant to the Plan, holders of Allowed General Unsecured Claims and Allowed Guaranty Claims will receive, among other things, Prisma Common Stock. For U.S. federal income tax purposes, Prisma is a "foreign corporation." A foreign corporation is classified as a PFIC for federal income tax purposes in any taxable year in which, after taking into account its pro-rata share of the gross income and assets of any company, U.S. or foreign, in which such foreign corporation is considered to own 25% or more of the shares by value, either (i) 75% or more of its gross income in the taxable year is passive income, or (ii) 50% or more of its assets (averaged over the year and ordinarily determined based on fair market value) are held for the production of, or produce, passive income.

The Debtors do not anticipate that Prisma will be a PFIC for its first taxable year and, based on Prisma's current business plan, do not anticipate that Prisma will become a PFIC. However, because the Debtors' expectations are based, in part, on interpretations of existing law as to which there is no specific guidance, and because the tests for PFIC status are applied annually, there can be no assurance that Prisma will not be treated as a PFIC. If Prisma is, or becomes, a PFIC, certain shareholders thereof may be subject to adverse U.S. federal income tax consequences upon receipt of distributions from Prisma or upon realizing a gain on the disposition of shares of Prisma Common Stock, including taxation of such amounts as ordinary income (which does not qualify for the reduced 15% tax rate applicable to certain "qualified dividend income") and the imposition of an interest charge on the resulting tax liability as if such ordinary income accrued over such shareholder's holding period for Prisma Common Stock.

Holders of Claims who may receive Prisma Common Stock under the Plan are urged to consult their own tax advisers regarding income derived from holding or disposing of Prisma Common Stock.

3. Distributions in Discharge of Accrued But Unpaid Interest

In general, to the extent that property received by a holder of an Allowed General Unsecured Claim or Allowed Guaranty Claim is received in satisfaction of interest accrued during its holding period, such amount will be taxable to the holder as interest income (if not previously included in the holder's gross income). Conversely, such a holder generally recognizes a deductible loss to the extent any accrued interest claimed or amortized OID was previously included in its gross income and is not paid in full. It is unclear whether a holder of a Claim with previously included OID that is not paid in full would be required to recognize a capital loss rather than an ordinary loss. Holders of claims for accrued interest including amortized OID should consult their own tax advisors.

Pursuant to the Plan, all distributions in respect of any Claim will be allocated first to the principal amount of such Claim, and thereafter, to accrued but unpaid interest, if any. However, there is no assurance that such allocation will be respected by the IRS for federal income tax purposes.

Each holder of an Allowed General Unsecured Claim, Allowed Enron Guaranty Claim, or Allowed Wind Guaranty Claim is urged to consult its tax advisor regarding the allocation of consideration and the deductibility of previously included unpaid interest and OID for tax purposes.

4. Tax Treatment of the Trusts and Holders of Beneficial Interests

As discussed above, in connection with the implementation of the Plan, holders of Allowed General Unsecured Claims and Allowed Guaranty Claims may receive interests in one or more of the Operating Trusts, and/or the Remaining Assets Trust and holders of Allowed General Unsecured Claims may also receive interests in one or more of the Litigation Trust and the Special Litigation Trust.

a. Classification of the Trusts. Each such trust is intended to qualify as "grantor trust" for federal income tax purposes. In general, a "grantor trust" is not a separate taxable entity. As such, assuming each trust is classified as a grantor trust the assets transferred to such trusts will be deemed for federal income tax purposes to have been transferred by Debtors to the appropriate holders of Allowed Claims pursuant to the Plan and such assets will be treated as being owned at all times thereafter by such holders of Allowed Claims. The IRS, in Revenue Procedure 94-45, 1994-2 C.B. 684, set forth the general criteria for obtaining an IRS ruling as to the grantor trust status of a liquidating trust under a chapter 11 plan. The Litigation Trust, the Special Litigation Trust, the Operating Trusts, and the Remaining Assets Trust have been structured with the intention of complying with such general criteria. Pursuant to the Plan, and in conformity with Revenue Procedure 94-45, all parties (including the Debtors, the trustees of the trusts and the appropriate holders of Allowed Claims) are required to treat the trusts, for federal income tax purposes, as grantor trusts of which the appropriate holders of Allowed Claims are the owners and grantors. The following discussion assumes that the trusts will be respected as grantor trusts for federal income tax purposes. The Creditors' Committee together with the Debtors has filed with the IRS a request for a ruling to that effect with respect to the Litigation Trust and the Special Litigation Trust; however, there is no assurance that such ruling will be obtained. Additionally, no opinion of counsel has been requested concerning the tax status of the trusts as grantor trusts. As a result, there can be no assurance that the IRS will treat the trusts as grantor trusts. If the IRS were to challenge successfully such classification, the federal income tax consequences to the trusts, the holders of Allowed Claims, and the Debtors could vary from those discussed herein (including the potential for an entity level tax on any income of the trusts).

b. General Tax Reporting by the Trusts and Beneficiaries. For all federal income tax purposes, the Plan requires all parties (including the Debtors, the trustees of the Litigation Trust, the Special Litigation Trust, the Operating Trusts and the Remaining Assets Trust, and the appropriate holders of Allowed General Unsecured Claims and Allowed Guaranty Claims) to treat the transfer of assets by the Debtors to the trusts, for federal income tax purposes, as a transfer of such assets directly to the appropriate holders of Allowed General Unsecured Claims and Allowed Guaranty Claims followed by the transfer of such assets by such holders of Allowed General Unsecured Claims and Allowed Guaranty Claims to the Trust. Consistent therewith, the Plan requires all parties to treat the trusts as grantor trusts of which such holders of Allowed General Unsecured Claims and Allowed Guaranty Claims are the owners and grantors. Thus, such holders of Allowed General Unsecured Claims and Allowed Guaranty Claims (and any subsequent transferees of interests in one of the applicable trusts) will be treated as the direct owners of a specified undivided interest in the assets of the applicable trust for all federal income tax purposes (which assets will have a tax basis equal to their fair market value on the date transferred to the trust). The Plan requires the trustee of each of the Litigation Trust, the Special Litigation Trust, the Operating Trusts, and the Remaining Assets Trust to determine the fair market value of the assets of the trust as of the date the assets are transferred to the trust and, further requires all parties, including the beneficiaries of such trusts, to consistently use such valuations in filing any required returns and reports with the IRS.

Accordingly, except as discussed below (in connection with the Disputed Claims Reserve), the Plan requires each holder of an Allowed General Unsecured Claims and Allowed Guaranty Claims that is a beneficiary of such trusts to report on its federal income tax return its allocable share of any income, gain, loss, deduction, or credit recognized or incurred by each trust, in accordance with its relative beneficial interest. The character of items of income, deduction, and credit to any beneficiary and the ability of such beneficiary to benefit from any deduction or bsses will depend on the particular situation of such beneficiary. The Disputed Claims Reserve will hold the beneficial interests in the trusts not owned by the beneficiaries and will report on its federal income tax return the portion of each trust's income, gain, loss, deduction, or credit attributable to the beneficial interest in the trust that it holds.

The federal income tax reporting obligation of a trust beneficiary is not dependent upon a trust distributing any cash or other proceeds. Therefore, a beneficiary may incur a federal income tax liability with respect to its allocable share of the income of a trust whether or not the trust has made any concurrent distribution to the beneficiary. In general, other than in respect of distributions attributable to a reduction in the Disputed Claims Reserve's interest in the Litigation Trust, the Special Litigation Trust, the Operating Trusts, and the Remaining Assets Trust and the forfeiture of unclaimed distributions, a distribution by a trust to an appropriate holder of an Allowed General Unsecured Claims and Allowed Guaranty Claims will not be taxable to such beneficiary because the beneficiaries are already regarded for federal income tax purposes as owning the underlying assets. Beneficiaries are urged to consult their tax advisors regarding the appropriate federal income tax treatment of distributions from the Trusts. Refer to Section XV.B.5., "Treatment of Disputed Claims Reserve" for additional information.

The trustee of each of the Litigation Trust, the Special Litigation Trust, the Operating Trusts, and the Remaining Assets Trust will file with the IRS returns for the trust as a grantor trust pursuant to Treasury Regulation section 1.671-4(a) and will also send to each applicable beneficiary of such trusts, a separate statement setting forth such beneficiary's share of items of income, gain, loss, deduction, or credit and will instruct the beneficiary to report such items on its federal income tax return.

5. Treatment of Disputed Claims Reserve

From and after the Effective Date, and until such time as all of the Debtors' assets (and the proceeds thereof) can be distributed to the holders of Allowed Claims in accordance with the terms of the Plan, the Disputed Claims Reserve will own a portion of the Plan Currency and interests in the trusts.

Distributions from the Disputed Claims Reserve will be made to holders of Disputed Claims when such Claims are subsequently Allowed and to holders of Allowed Claims (whether such Claims were Allowed on or after the Effective Date) when any Disputed Claims are subsequently disallowed. In addition, to the extent that it is necessary for assets to be held in the Disputed Claims Reserve pending the sale of Remaining Assets (in order to determine which holders of Allowed General Unsecured Claims and Allowed Guaranty Claims are entitled to receive distributions thereof under the terms of the Plan), distributions from the Disputed Claims Reserve will also be made to such holders when sales of (or certain other circumstances in respect of) such Remaining Assets occur. Such distributions (other than amounts attributable to earnings) should be taxable to the recipient in accordance with the principles discussed above in "Gain or Loss – Generally."

a. Disputed Claim Reserve – Federal Income Tax – General. Under Section 468B(g) of the IRC, amounts earned by an escrow account, settlement fund, or similar fund are subject to current tax. Although certain Treasury Regulations have been issued under this section, no final Treasury Regulations have as yet been promulgated to address the tax treatment of such accounts in a bankruptcy setting. Thus, depending on the facts of a particular situation, such an account could be treated as a separately taxable trust, as a grantor trust treated as owned by the holders of Disputed Claims or by the Debtors (or, if applicable, any of its successors), or otherwise. On February 1, 1999, the IRS issued proposed Treasury Regulations that, if finalized in their current form, would specify the tax treatment of escrows of the type here involved that are established after the date such Treasury Regulations become final. In general, such Treasury Regulations would tax such an escrow in a manner similar to a corporation. As to previously established escrows, such Treasury Regulations would provide that the IRS would not challenge any reasonably and consistently applied method of taxation for income earned by the escrow, and any reasonably and consistently applied method for reporting such income.

b. Disputed Claim Reserve – Federal Income Tax – Intended Treatment by Debtors. Absent definitive guidance from the IRS or a court of competent jurisdiction to the contrary (including the issuance of applicable final Treasury Regulations, the receipt by the Disbursing Agent of a private letter ruling if the Disbursing Agent so requests one, or the receipt of an adverse determination by the IRS upon audit if not contested by the Disbursing Agent), the Disbursing Agent shall (i) treat the Disputed Claims Reserve as one or more discrete trusts (which may consist of separate and independent shares) for federal income tax purposes in accordance with the trust provisions of the IRC (sections 641 et seq.), and (ii) to the extent permitted by applicable law, report consistently for state and local income tax purposes. The Plan requires all parties to consistently follow such treatment in filing any returns and reports with the IRS.

Accordingly, subject to issuance of definitive guidance, the Disbursing Agent will report as subject to a separate entity level tax any amounts earned by the Disputed Claims Reserve including any taxable income of the Litigation Trust, the Special Litigation Trust, the Operating Trusts, and the Remaining Assets Trust allocable to the Disputed Claims Reserve, except to the extent such earnings or income are distributed by the Disbursing Agent during the same taxable year. In such event, the amount of earnings or income that is so distributed to an Allowed Claim holder during the same taxable year will be includible in such holder's gross income.

c. Disputed Claim Reserve –Financing of Tax Obligations. If the Disputed Claims Reserve has insufficient funds to pay any applicable taxes imposed upon it or its assets, the Reorganized Debtors will make a Tax Advance to the Disputed Claims Reserve. Any such Tax Advance will be repayable from future amounts otherwise receivable by the Disputed Claims Reserve.

If and when a distribution is to be made from the Disputed Claims Reserve, the distributee will be charged its pro rata portion of any outstanding Tax Advance (including accrued interest). If a cash distribution is to be made to such distributee, the Disbursing Agent shall be entitled to withhold from such distributee's distribution the amount required to pay such portion of the Tax Advance (including accrued interest). If such cash is insufficient to satisfy the respective portion of the Tax Advance and there is also to be made to such distributee a distribution of other Plan Currency or Trust interests, the distributee shall as a condition to receiving such other assets pay in cash to the Disbursing Agent an amount equal to the unsatisfied portion of the Tax Advance (including accrued interest). Failure to make such payment shall entitle the Disbursing Agent to reduce and permanently adjust the amounts that would otherwise be distributed to such distributee to fairly compensate the Disputed Claims Reserve for the unpaid portion of the Tax Advance (including accrued interest).

In light of the foregoing, each holder of an Allowed Claim is urged to consult its tax advisors regarding the potential tax treatment of the Disputed Claim Reserve, distributions therefrom, and any tax consequences to such holder relating thereto.

6. Withholding and Certain Information Reporting

All distributions to holders of Allowed Convenience Claims, Allowed General Unsecured Claims and Allowed Guaranty Claims under the Plan are subject to any applicable tax withholding, including employment tax withholding. Under federal income tax law, interest, dividends, and other reportable payments may, under certain circumstances, be subject to "backup withholding" at the then applicable withholding rate (currently 28%). Backup withholding generally applies if the holder (a) fails to furnish its social security number or other taxpayer identification number, (b) furnishes an incorrect taxpayer identification number, (c) fails properly to report interest or dividends, or (d) under certain circumstances, fails to provide a certified statement, signed under penalty of perjury, that the tax identification number provided is its correct number and that it is not subject to backup withholding. Backup withholding is not an additional tax but merely an advance payment, which may be refunded to the extent it results in an overpayment of tax. Certain persons are exempt from backup withholding, including, in certain circumstances, corporations and financial institutions.

Recently effective Treasury Regulations generally require disclosure by a taxpayer on its federal income tax return of certain types of transactions in which the taxpayer participated on or after January 1, 2003, including, among other types of transactions, the following (1) a transaction offered under "conditions of confidentiality"; (2) a transaction where the taxpayer was provided contractual protection for a refund of fees if the intended tax consequences of the transaction are not sustained; (3) certain transactions that result in the taxpayer claiming a loss in excess of specified thresholds; and (4) a transaction in which the taxpayer's federal income tax treatment differs by more than a specified threshold in any tax year from its treatment for financial reporting purposes. These categories are very broad; however, there are numerous exceptions. Holders of Allowed Convenience Claims, Allowed General Unsecured Claims and Allowed Guaranty Claims are urged to consult their tax advisors regarding these regulations and whether the transactions contemplated by the Plan would be subject to these regulations and require disclosure on the holders' tax returns.

The foregoing summary has been provided for informational purposes only. All holders of Claims are urged to consult their tax advisors concerning the federal, state, local, and foreign tax consequences applicable under the Plan.

XVI. Conditions Precedent To Effective Date Of The Plan

Capitalized terms used throughout this Disclosure Statement are defined in Appendix A: "Material Defined Terms for Enron Disclosure Statement" attached hereto.

A. Conditions Precedent to Effective Date of the Plan

The occurrence of the Effective Date and the substantial consummation of the Plan are subject to satisfaction of the following conditions precedent:

1. Entry of the Confirmation Order

The Clerk of the Bankruptcy Court shall have entered the Confirmation Order, in form and substance reasonably satisfactory to the Debtors and the Creditors' Committee and the effectiveness of which shall not have been stayed ten (10) days following the entry thereof.

2. Execution of Documents; Other Actions

All other actions and documents necessary to implement the Plan shall have been effected or executed.

3. Prisma Consents Obtained

The requisite consents to the transfer of the Prisma Assets and the issuance of the Prisma Common Stock have been obtained.

4. CrossCountry Consents Obtained

The requisite consents to the issuance of the CrossCountry Common Stock have been obtained.

5. PGE Consents Obtained

The requisite consents for the issuance of the PGE Common Stock have been obtained.

6. Waiver of Conditions Precedent

To the extent practicable or legally permissible, each of the conditions precedent in Section 37.1 of the Plan, may be waived, in whole or in part, by the Debtors with the consent of the Creditors' Committee. Any such waiver of a condition precedent may be effected at any time by filing a notice thereof with the Bankruptcy Court.

7. Alternative Structures

Notwithstanding anything contained in the Plan to the contrary, the Debtors, if jointly determined after consultation with the Creditors' Committee, may, after obtaining the requisite approvals, (a) form one (1) or more holding companies to hold the common stock of the Entities to be issued under the Plan and issue the equity interest therein in lieu of the common stock to be issued under the Plan and (b) form one (1) or more limited liability companies in lieu of the Entities to be created under the Plan and issue the membership interests therein in lieu of the common stock to be issued under the Plan; provided, however, that no such structures shall materially adversely affect the substance of the economic and governance provisions contained in the Plan.

B. Alternative Plan(s) of Reorganization

The Debtors have evaluated numerous reorganization alternatives to the Plan. After evaluating these alternatives, the Debtors have concluded that the Plan, assuming confirmation and successful implementation, is the best alternative and will maximize recoveries by holders of Claims. If the Plan is not confirmed, then the Debtors could remain in chapter 11. Should this occur, then the Debtors could continue to operate their businesses and manage their properties as debtors in possession, but they would remain subject to the restrictions imposed by the Bankruptcy Code. Moreover, the Debtors (whether individually or collectively) or, subject to further determination by the Bankruptcy Court as to extensions of exclusivity under the Bankruptcy Code, any other party in interest could attempt to formulate and propose a different plan or plans. This would take time and result in an increase in the operating and other administrative expenses of these Chapter 11 Cases. The Debtors believe that the Plan, as described herein, enables holders of Claims to realize the greatest recovery under the circumstances.

Notwithstanding anything contained in the Plan to the contrary, the Debtors, if jointly determined after consultation with the Creditors' Committee, may, after obtaining the requisite approvals, (a) form one (1) or more holding companies to hold the common stock of the Entities to be created hereunder and issue the equity interest therein in lieu of the common stock to be issued hereunder and (b) form one (1) or more limited liability corporations in lieu of the Entities to be created in accordance with the Plan and issue the membership interests therein in lieu of the common stock to be issued in accordance with the Plan.

C. Liquidation Under Chapter 7

If no chapter 11 plan can be confirmed, then the Debtors' cases may be converted to cases under chapter 7 of the Bankruptcy Code, whereby a trustee would be elected or appointed to liquidate the assets of the Debtors for distribution to the holders of Claims in accordance with the strict priority scheme established by the Bankruptcy Code.

Under chapter 7, the cash amount available for distribution to Creditors would consist of the proceeds resulting from the disposition of the unencumbered assets of the Debtors, augmented by the unencumbered cash held by the Debtors at the time of the commencement of the liquidation cases. Such cash amount would be reduced by the costs and expenses of the liquidation and by such additional administrative and priority claims that may result from the termination of the Debtors' businesses and the use of chapter 7 for the purposes of liquidation.

The Debtors have analyzed liquidation in the context of chapter 7 and the Liquidation Analysis attached as Appendix L: "Liquidation Analysis" reflects the Debtors' estimates regarding recoveries in a chapter 7 liquidation. The Liquidation Analysis is based upon the hypothetical disposition of assets and distribution on Claims under a chapter 7 liquidation in contrast to the distribution of Creditor Cash, Plan Securities and interests in the Litigation Trust and the Special Litigation Trust under the Plan. The Liquidation Analysis assumes that, in the chapter 7 cases, the Bankruptcy Court will approve the settlements and compromises embodied in the Plan and described in the Disclosure Statement (including, without limitation, the 30/70 compromise regarding the likelihood of substantive consolidation) as fair and reasonable and determines that the compromise represents the best estimate, short of a final determination on the merits, of how these issues would be resolved. The Liquidation Analysis further takes into consideration the increased costs of a chapter 7 liquidation, the impact on the value of the three Operating Entities and the expected delay in distributions to Creditors.

The Debtors submit that the Liquidation Analysis evidences that the Plan satisfies the best interest of creditors test and that, under the Plan, each holder of an Allowed General Unsecured Claim will receive value that is not less than the amount such holder would receive in a chapter 7 liquidation. Further, the Debtors believe that pursuant to chapter 7 of the Bankruptcy Code, holders of Enron Subordinated Debenture Claims, Enron Preferred Equity Interests, Statutorily Subordinated Claims, Enron Common Equity Interests and Other Equity Interests would receive no distributions.

Estimating recoveries in any chapter 7 case is an uncertain process due to the number of unknown variables such as business, economic and competitive contingencies beyond the chapter 7 trustee's control, and this uncertainty is further aggravated by the complexities of these Chapter 11 Cases. The underlying projections contained in the Liquidation Analysis have not been compiled or examined by independent accountants. The Debtors make no representations regarding the accuracy of the projections or a chapter 7 trustee's ability to achieve forecasted results. Many of the assumptions underlying the projections are subject to significant uncertainties. Inevitably, some assumptions will not materialize and unanticipated events and circumstances may affect the ultimate financial results. In the event these Chapter 11 Cases are converted to chapter 7, actual results may vary materially from the estimates and projections set forth in the Liquidation Analysis. As such, the Liquidation Analysis is speculative in nature.

XVII. Claims Allowance, Objection and Estimation Procedures

Capitalized terms used throughout this Disclosure Statement are defined in Appendix A: "Material Defined Terms for Enron Disclosure Statement" attached hereto.

A. Schedules of Assets and Liabilities and Statements of Financial Affairs

Under Bankruptcy Rule 1007(c), the Debtors are required to file their Schedules within 15 days of the filing of the bankruptcy petition. On April 12, 2002, the Bankruptcy Court entered an order (a) setting June 17, 2002 as the deadline for the first 51 Debtors to file their Schedules and (b) granting any Debtors filing petitions subsequent to March 1, 2002 an extension of 120 days from the fifteen-day period after any such Debtor's respective Petition Date to file their Schedules. Refer to Appendix D: "Filing of Schedules and Statements" for a list of Debtors, the dates on which they filed their Schedules, and the date of the Applicability Order that was entered for each Debtor.

As explained in a November 8, 2001 Form 8-K filed by ENE with the SEC, the previously issued financial statements of ENE for the fiscal years ended December 31, 1997 through 2000 and for the first and second quarters of 2001 and the audit reports covering the year-end financial statements for 1997 through 2000 should not be relied upon. In addition, as explained in an April 22, 2002 Form 8-K filed by ENE, the financial statements of ENE for the third quarter of 2001 should not be relied upon. Following the Initial Petition Date, in conjunction with the preparation of their Schedules, review and analysis of proofs of claim, and formulation of the Plan, the Debtors have expended substantial efforts to review and reconcile their books and records. As a result of these postpetition efforts, in some instances, the assets and liabilities listed on a Debtor's Schedules may vary from the information reflected on that Debtor's chapter 11 voluntary petition. In addition, as a result of these efforts and the ongoing claims process in these Chapter 11 Cases, the assets and liabilities listed on a Debtor's chapter 11 voluntary petition and/or a Debtor's Schedules may vary from the information reflected on Appendix C: "Estimated Assets, Claims and Distributions".

B. Claims Bar Date and Notice of the Bar Date

By order dated August 1, 2002 (as modified on October 23, 2003), the Bankruptcy Court set the Claims Bar Date, depending on when each Debtor filed its Schedules. Refer to Appendix D: "Filing of Schedules and Statements" for further information about the Claims Bar Date for each Debtor.

In accordance with that order, notices informing Creditors of the last date to timely file proofs of claims were and will be mailed at least 45 days prior to the Claims Bar Date relating to each respective Debtor, along with a customized proof of claim form. In addition, consistent with that order, the Debtors caused and will continue to cause to be published in the Houston Chronicle, the national editions of The Wall Street Journal and New York Times, and the Financial Times, a notice of each Claims Bar Date listed above. In addition, notice of the October 15, 2002 Claims Bar Date was published in the Los Angeles Times, The Oregonian, and the Omaha World-Herald. Notice of the October 31, 2002 Claims Bar Date was also published in the Seattle Times Post-Intelligencer and El Nuevo Dia. Additionally, the Debtors published notice of the December 2, 2002 Claims Bar Date in the Los Angeles Times, the Seattle Times Post-Intelligencer, and El Nuevo Dia.

Debenture holders and stockholders did not need to file a proof of claim or proof of interest to preserve their debenture claims or stock interests. The records of the indenture trustees will be relied on as evidence of the debenture claims, and the records of the stock transfer agent will be relied on as evidence of the stock interests.

Pursuant to the Bankruptcy Court's August 1, 2002 order, no Claims Bar Date was set for any Debtor or majority-owned non-Debtor affiliate to file Claims against any Debtor. The Debtors are relying upon their Schedules (as the same may be amended or supplemented from time to time) for purposes of allowance and distribution of Claims held by any Debtor against another Debtor or by any majority-owned non-Debtor affiliate against any Debtor.

C. Allowance and Impairment of Claims

To be entitled to receive a distribution under the Plan, a Creditor must have an Allowed Claim. To be entitled to vote on the Plan, however, a Creditor must have an Allowed Claim that is also impaired. If a Claim is not Allowed, the Creditor will not be entitled to vote on the Plan or to receive a distribution. Any Class as to which no distribution will be made under the Plan under any circumstances does not vote on the Plan and is deemed not to have accepted it. Any Class that is not impaired will be deemed to have accepted the Plan.

1. Allowance of Claims

A Claim is automatically Allowed if (i) a proof of claim has been filed and no objections to the Claim are asserted, or (ii) the Claim is listed in the Debtors' Schedules and is not listed as disputed, contingent, or unliquidated.

If a proof of claim is filed and an objection to that Claim is asserted, the objection must be resolved before the Claim will be Allowed. If a Claim is scheduled on the Debtors' Schedules as disputed, contingent, or unliquidated, the Claim is not Allowed unless (i) a proof of claim is filed on or before the Claims Bar Date, and (ii) objections to the proof of claim are resolved by a Final Order of the Bankruptcy Court. The Debtors' Schedules are too voluminous to reproduce in this Disclosure Statement, but have been filed with the Bankruptcy Court and may be reviewed there by Creditors.

2. Impairment of Claims

Under section 1124 of the Bankruptcy Code, a class of claims is impaired under a plan unless, with respect to each claim of such class, (i) it is paid in full on the effective date of the plan; (ii) the plan leaves unaltered the legal, equitable, and contractual rights to which such claim is entitled; or (iii) all defaults are cured, the original maturity of the claim is reinstated, and the claim is otherwise treated as provided in clause (ii).

D. Objections to Claims

1. General

In excess of 24,000 proofs of claim asserting Claims against the Debtors have been filed with the Bankruptcy Court. The aggregate amount of Claims filed and scheduled exceeds $900 billion, including duplication, but excluding any estimated amounts for contingent or unliquidated Claims. From March 7, 2003 through November 7, 2003, the Debtors filed 20 omnibus objections to proofs of claim and various other objections to claims, which resulted in the subsequent disallowance and expungement of over 6,600 proofs of claim totaling over $106 billion. As of November 7, 2003, the Debtors have pending hearings on objections covering over 800 proofs of claim for a total of over $44 billion, which are set for hearing through January 15, 2004. In addition, the Bankruptcy Court has approved stipulations disallowing or reducing the claimed amounts by more than $5 billion. Moreover, the Bankruptcy Court has taken under advisement the Debtors' objection to a $10.5 billion claim.

The Debtors are in the process of evaluating the proofs of claim to determine whether additional objections seeking the disallowance of some asserted Claims should be filed. The Debtors are reconciling the scheduled Claims with the Claims asserted in proofs of claim and are continuing to eliminate duplication and other inaccuracies to ensure that only valid claims are allowed by the Bankruptcy Court. The Debtors anticipate filing additional objections addressing a substantial portion of the remaining filed proofs of claim. The disallowed amount will continue to increase as the Debtors file more objections to the asserted Claims for amounts that the Debtors believe are invalid. The Debtors and Reorganized Debtors reserve their rights to object to assigned claims and seek their equitable subordination if such claims could have been subordinated in the hands of the assignors. The Plan provides that the Reorganized Debtors shall file and serve all objections to Claims within 240 days after the Effective Date or such later date as may be approved by the Bankruptcy Court.

E. Estimation Procedures

On August 28, 2003, the Debtors filed a motion seeking approval to implement procedures whereby the Bankruptcy Court will estimate, for purposes of distribution under the Plan, Claims filed in the Debtors' Chapter 11 Cases, and adjudicate related counterclaims in connection with trading contracts. The motion is set for hearing on December 4, 2003 with a status conference to be held on November 13, 2003. The claim procedures contemplated in the motion provide the Debtors and their creditors the opportunity to negotiate with each other to settle Claims and counterclaims pursuant to Bankruptcy Court-approved procedures. After the Debtors move to estimate a particular Claim and prior to an estimation hearing, the Debtors may extend an offer to resolve such claim, and a claimant may accept, reject, or extend a counteroffer. Subject to certain amount limitations and approvals by the Creditors' Committee, a stipulation and agreed order shall memorialize any settlement of a Claim reached by the parties. If the Debtors and Creditors are unable to agree to a settlement of a particular Claim, the claim procedures provide that all parties proceed to a hearing before the Bankruptcy Court and conduct such hearing in accordance with structured guidelines to estimate and allow unliquidated, and contingent claims for all purposes under the Bankruptcy Code in these cases.

XVIII. Voting Procedures

Capitalized terms used throughout this Disclosure Statement are defined in Appendix A: "Material Defined Terms for Enron Disclosure Statement" attached hereto.

Classes 1 and 2 of the Plan are unimpaired. As a result, holders of Claims in those Classes are conclusively presumed to have accepted the Plan and are not entitled to vote.

Classes 3 through 182, 185 through 189 and 191 through 375 of the Plan are impaired and, to the extent Claims in such Classes are Allowed Claims, the holders of such Claims will receive distributions under the Plan. As a result, holders of Claims in those Classes are entitled to vote to accept or reject the Plan pursuant to the voting, solicitation and tabulation procedures approved by the Bankruptcy Court. Refer to Exhibit 2: "Disclosure Statement Order" and Exhibit 3: "Voting Procedures Order" for additional information.

Class 190 of the Plan, consisting of Intercompany Claims, is presumed to have accepted the Plan and all holders of such Claims are proponents of the Plan. As a result, holders of Claims in Class 190 are not entitled to vote.

Classes 183, 184, and 376 through 385 of the Plan, consisting of certain holders of Claims and all holders of Equity Interests, will not receive any distributions under the Plan. As a result, holders of Claims and Equity Interests in Classes 183, 184, and 376 through 385 are conclusively presumed to have rejected the Plan and are not entitled to vote.

XIX. Confirmation Of The Plan

Capitalized terms used throughout this Disclosure Statement are defined in Appendix A: "Material Defined Terms for Enron Disclosure Statement" attached hereto.

The Plan will not constitute a valid, binding contract between the Debtors and their creditors until the Bankruptcy Court has entered a Final Order confirming the Plan. The Bankruptcy Court must hold a confirmation hearing before deciding whether to confirm the Plan.

A. Confirmation Hearing

The Bankruptcy Court has ordered that the hearing on confirmation of the Plan will begin on [_____________, 2003] at [__:__ _.m. New York City Time], in Room 523 of the United States Bankruptcy Court for the Southern District of New York, One Bowling Green, New York, New York and will continue thereafter until concluded. The Confirmation Hearing may be adjourned from time to time by the Bankruptcy Court without further notice except for an announcement made at the Confirmation Hearing or any subsequent adjournment of that hearing.

B. Requirements for Confirmation of the Plan

At the Confirmation Hearing, the Bankruptcy Court will determine whether the Plan satisfies the requirements for confirmation listed in section 1129 of the Bankruptcy Code. If the Bankruptcy Court determines that those requirements are satisfied, it will enter an order confirming the Plan. As set forth in section 1129 of the Bankruptcy Code, the requirements for confirmation are as follows:

1. The plan complies with the applicable provisions of the Bankruptcy Code.

2. The proponent of the plan complies with the applicable provisions of the Bankruptcy Code.

3. The plan has been proposed in good faith and not by any means forbidden by law.

4. Any payment made or promised by the proponent of the plan, by the debtor, or by a person issuing securities or acquiring property under the plan, for services or for costs and expenses in, or in connection with, the case, or in connection with the plan and incident to the case, has been approved by, or is subject to the approval of, the Bankruptcy Court as reasonable.

5. a. The proponent of the plan has disclosed:

(1) the identity and affiliations of any individual proposed to serve, after confirmation of the plan, as a director, officer, or voting trustee of the debtor, an affiliate of the debtor participating in a joint plan with the debtor, or a successor to the debtor under the plan; and

(2) the appointment to, or continuance in, the office of the individual, is consistent with the interests of creditors and equity security holders and with public policy.

b. The proponent of the plan has disclosed the identity of any insider that will be employed or retained by the reorganized debtor, and the nature of any compensation for the insider.

6. Any governmental regulatory commission with jurisdiction, after confirmation of the plan, over the rates of the debtor has approved any rate change provided for in the plan, or the rate change is expressly conditioned on such approval.

7. With respect to each impaired class of claims or interests:

a. Each holder of a claim or interest of the class has

(1) accepted the plan; or

(2) will receive or retain under the plan on account of the claim or interest property of a value, as of the effective date of the plan, that is not less than the amount that the holder would so receive or retain if the debtor were liquidated under chapter 7 of the Bankruptcy Code on that date; or

b. If section 1111(b)(2) of the Bankruptcy Code applies to the claims of the class, the holder of the claim of the class will receive or retain under the plan property of a value, as of the effective date of the plan, that is not less than the value of the holder's interest in the estate's interest in the property that secures the claim.

8. With respect to each class of claims or interests:

a. The class has accepted the plan; or

b. The class is not impaired under the plan.

9. Except to the extent that the holder of a particular claim has agreed to a different treatment of the claim, the plan provides that:

a. With respect to a claim of a kind specified in section 507(a)(1) or 507(a)(2) of the Bankruptcy Code, on the effective date of the plan, the holder of the claim will receive on account of the claim cash equal to the allowed amount of the claim;

b. With respect to a class of claims of a kind specified in section 507(a)(3), 507(a)(4), 507(a)(5), or 507(a)(6) of the Bankruptcy Code, each holder of a claim of the class will receive:

(1) if the class has accepted the plan, deferred cash payments of a value, as of the effective date of the plan, equal to the allowed amount of the claim; or

(2) if the class has not accepted the plan, cash on the effective date of the plan equal to the allowed amount of the claim; and

c. With respect to a claim of a kind specified in section 507(a)(7) of the Bankruptcy Code, the holder of a claim will receive on account of the claim deferred cash payments, over a period not exceeding six years after the date of assessment of such claim, of a value, as of the effective date of the plan, equal to the allowed amount of such claim.

10. If a class of claims is impaired under the plan, at least one class of claims that is impaired has accepted the plan, determined without including any acceptance of the plan by any insider holding a claim of the class.

11. Confirmation of the plan is not likely to be followed by the liquidation, or the need for further financial reorganization, of the debtor or any successor to the debtor under the plan, unless such liquidation or reorganization is proposed in the plan.

12. All fees payable under 28 U.S.C. § 1930, as determined by the Bankruptcy Court at the hearing on confirmation of the plan, have been paid or the plan provides for the payment of all such fees on the effective date of the plan.

13. The plan provides for the continuation after its effective date of payment of all retiree benefits, as that term is defined in section 1114 of the Bankruptcy Code, at the level established pursuant to subsection (e)(1)(B) or (g) of section 1114, at any time prior to confirmation of the plan, for the duration of the period the debtor has obligated itself to provide the benefits.

The Debtors believe that the Plan satisfies all of the statutory requirements of chapter 11 of the Bankruptcy Code, that the Debtors have complied or will have complied with all of the requirements of chapter 11, and that the Plan is proposed in good faith.

The Debtors believe that holders of all Allowed Claims impaired under the Plan will receive payments under the Plan having a present value as of the Effective Date not less than the amounts they would likely receive if the Debtors were liquidated in a case under chapter 7 of the Bankruptcy Code. At the Confirmation Hearing, the Bankruptcy Court will determine whether holders of Allowed Claims would receive greater distributions under the Plan than they would have received in a liquidation under chapter 7 of the Bankruptcy Code.

1. Acceptance

Claims in Classes 1 and 2 are unimpaired by the Plan, and the holders thereof are conclusively presumed to have accepted the Plan.

Claims in Classes 3 through 182, 185 through 189, and 191 through 375 are impaired under, and the holders of such Claims are entitled to vote on the Plan and, therefore, must accept the Plan in order for it to be confirmed without application of the "*fair and equitable test*" described below, to such Classes. A Class of Claims is deemed to have accepted the Plan if the Plan is accepted by at least two-thirds in dollar amount and a majority in number of the Claims of each such Class (other than any Claims of creditors designated under section 1126(e) of the Bankruptcy Code) that have voted to accept or reject the Plan.

Claims in Class 190 are held by the Debtors who are the proponents of the Plan. The Debtors are presumed to have accepted the Plan.

Claims and Equity Interests in Classes 183, 184, and 376 through 385 are impaired; however, holders of such Claims or Interests will not receive or retain property under the Plan and, therefore, such classes are deemed not to have accepted the Plan. Accordingly, confirmation of the Plan will require application of the "*fair and equitable test*" described below to such Classes.

2. "Cramdown" under the Fair and Equitable Test

The Debtors will seek to confirm the Plan notwithstanding the nonacceptance or deemed nonacceptance of the Plan by any impaired Class of Claims or Equity Interests. To obtain such confirmation, it must be demonstrated to the Bankruptcy Court that the Plan "does not discriminate unfairly" and is "fair and equitable" with respect to such dissenting impaired Classes. A plan does not discriminate unfairly if the legal rights of a dissenting class are treated in a manner consistent with the treatment of other classes whose legal rights are substantially similar to those of the dissenting class and if no class receives more than it is entitled to for its claims or equity interests. The Debtors believe that the Plan satisfies this requirement.

The Bankruptcy Code establishes different "fair and equitable" tests for secured claims, unsecured claims and equity interests, and a "cramdown" of the Plan, as follows:

a. **Secured Claims**. Either the plan must provide (i) that the holders of such claims retain the liens securing such claims, whether the property subject to such liens is retained by the debtor or transferred to another entity, to the extent of the allowed amount of such claims, and each holder of a claim receives deferred cash payments totaling at least the allowed amount of such claim, of a value, as of the effective date of the plan, of at least the value of such holder's interest in the estate's interest in such property; (ii) for the sale of any property that is subject to the liens securing such claims, free and clear of such liens, with such liens to attach to the proceeds of such sale; or (iii) for the realization by such holders of the indubitable equivalent of such claims.

b. **Unsecured Claims**. Either (i) each holder of an impaired unsecured claim receives or retains under the plan property of a value equal to the amount of its allowed claim or (ii) the holders of claims and interests that are junior to the claims of the dissenting class will not receive any property under the plan.

c. **Equity Interests**. Either (i) each equity interest holder will receive or retain under the plan property of a value equal to the greater of (x) the fixed liquidation preference or redemption price, if any, of such stock or (y) the value of the stock, or (ii) the holders of interests that are junior to the stock will not receive any property under the plan.

d. **"Cramdown" of the Plan**. Classes 183, 184, and 376 through 385 are deemed to reject the Plan. Notwithstanding the deemed rejection of such classes, the Bankruptcy Court may still confirm the Plan if, as to each impaired class that has not accepted the Plan, the Plan does not discriminate unfairly and is fair and equitable. In the event that one or more classes of impaired Claims rejects the Plan, the Bankruptcy Court will determine at the Confirmation Hearing whether the Plan is fair and equitable with respect to, and does not discriminate unfairly against, any rejecting impaired class of Claims.

THE DEBTORS BELIEVE THAT THE PLAN MAY BE CONFIRMED ON A NONCONSENSUAL BASIS SO LONG AS AT LEAST ONE IMPAIRED CLASS OF CLAIMS VOTES TO ACCEPT THE PLAN. ACCORDINGLY, THE DEBTORS WILL DEMONSTRATE AT THE CONFIRMATION HEARING THAT THE PLAN SATISFIES THE REQUIREMENTS OF SECTION 1129(b) OF THE BANKRUPTCY CODE AS TO ANY NON-ACCEPTING CLASS.

3. Feasibility

The Bankruptcy Code permits a chapter 11 plan to be confirmed if it is not likely to be followed by liquidation or the need for further financial reorganization, other than as provided in the Plan. For purposes of determining whether the Plan meets this requirement, the Debtors have analyzed their ability to meet their obligations under the Plan. The Debtors believe that they will be able to make all payments required pursuant to the Plan and that the confirmation of the Plan is not likely to be followed by additional liquidation or the need for further reorganization.

4. "Best Interests" Test

With respect to each impaired Class of Claims and Equity Interests, confirmation of the Plan requires that each such holder either (a) accepts the Plan or (b) receives or retains under the Plan property of a value, as of the Effective Date of the Plan, that is not less than the value such holder would receive or retain if the Debtors were liquidated under chapter 7 of the Bankruptcy Code.

This analysis requires the Bankruptcy Court to determine what the holders of Allowed Claims and Allowed Equity Interests in each impaired Class would receive from the liquidation of the Debtors' assets and properties in the context of chapter 7 liquidation cases. Refer to Section XVI.C., "Liquidation Under Chapter 7" for further information.

To determine if the Plan is in the best interests of each impaired Class, the value of the distributions from the proceeds of the liquidation of the Debtors' assets and properties (after subtracting the amounts attributable to the aforesaid claims) is then compared with the value offered to such Classes of Claims and Equity Interests under the Plan.

In applying the "*best interests*" test, it is possible that the Claims and Equity Interests in chapter 7 cases may not be classified according to the seniority of such Claims and Equity Interests, but instead be subjected to contractual or equitable subordination.

C. Objections To Confirmation Of The Plan

The Bankruptcy Court has ordered that all objections to confirmation of the Plan must be filed with the Bankruptcy Court and served by [__:__ _.m. New York City Time] on [_________, 2003]. Objections must be written in the English language, must specifically detail the reasons for the objection to confirmation of the Plan, and must be served on the following:

Enron Corp.
1400 Smith Street
Houston, Texas 77002
Attention: General Counsel

Weil, Gotshal & Manges LLP
767 Fifth Avenue
New York, New York 10153
Attention: Martin J. Bienenstock, Esq.

Brian S. Rosen, Esq.

Milbank, Tweed, Hadley & McCloy LLP
One Chase Manhattan Plaza
New York, New York 10005
Attention: Luc A. Despins, Esq.
Susheel Kirpalani, Esq.

The Office of the United States Trustee
33 Whitehall Street, 21st Floor
New York, New York 10004
Attention: Mary Elizabeth Tom, Esq.

Davis, Polk & Wardwell
450 Lexington Avenue
New York, New York 10017
Attention: Donald S. Bernstein, Esq.

Shearman & Sterling
599 Lexington Avenue
New York, New York 10022
Attention: Fredric Sosnick, Esq.

Section 1128(b) of the Bankruptcy Code provides that any party in interest may object to confirmation of a plan. Objections to confirmation of the Plan are governed by Bankruptcy Rule 9014. UNLESS AN OBJECTION TO CONFIRMATION OF THE PLAN IS TIMELY SERVED AND FILED, IT WILL NOT BE CONSIDERED BY THE BANKRUPTCY COURT.

XX. Conclusion

All holders of Claims against the Debtors are urged to vote to accept the Plan and to evidence such acceptance by returning their Ballots so that they will be received by ____________________, 2003.

Dated: November 13, 2003
Houston, Texas

Respectfully submitted,

ENRON CORP., et al.,
Debtors in Possession

By: /s/ Stephen F. Cooper
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